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Department of Marine Technology

Master Thesis

| Title: | Delivered: |
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| Alternative methods for reduction of operational downtime related to dis-/reconnection of the marine drilling riser<br>(System for rask tilkobling og frakobling av marin riser i forbindelse med boring i artisk område.) | June 3, 2011<br>**Availability:**<br>Open |
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**Abstract:**

The global energy demand is increasing. The oil companies are going into harsher climates and deeper waters to replace their reserves. Much of the undiscovered hydrocarbon reservoirs are believed to be located in the Arctic region. The seasonable ice free waters surrounding the Arctic can be drilled utilizing conventional drilling vessels designed for open water conditions. The region introduces several new operational challenges leading to an increased possibility of the drilling vessel moving off location.

This Master Thesis looks at the challenges related to operating a conventional drilling vessel in the seasonable open waters in the Arctic, using today's methods for disconnecting and reconnecting the marine drilling riser from the BOP.

The need for a reduction in the operational downtime related to planned and unplanned disconnections is identified and several alternative methods for reducing the dis-/reconnect time are presented and rated.

A concept is chosen based on a wide range of design requirements thus leading to an 89-97 % reduction in costs related to planned and unplanned disconnections, depending on water depth and well type.

The operational subsea control system needs are mapped and several possible control options are presented and evaluated. Based on a Preliminary Hazard Analysis, cost and system complexity, a control system is chosen.

**Keyword:**

- Drilling in the Arctic
- Deepwater drilling
- Disconnection and reconnection

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**MASTER THESIS**

**for**

**M.Sc. student Andreas Djupesland**

**Department of Marine Technology**

**Spring 2011**

# System for quick disconnect and re- connect of marine drilling riser in arctic areas.

**(System for rask tilkobling og frakobling av marin riser i forbindelse med boring i artisk område.)**

Due to large forces from drifting ice in arctic areas, drilling operations from a floater might require quick disconnect from the subsea wellhead. Existing methods for emergency quick disconnect of the marine drilling riser (typical 30 sec. in an emergency situation) might not be acceptable since re-connection is very time consuming and risky.

The procedures for planned disconnection are also too time consuming. For a water depth of 500 m, the time for planned disconnect might be 2-3 hours. Part of the drill string has to be pulled to install a "disconnection sub" in the drill string. Then the sub along with the drill string is lowered into the wellhead to suspend the drill string before disconnection of drill string and riser.

This project aims to investigate a new system and procedure which allows quick disconnect and re-connect of the drill string and the marine drilling riser. The time for disconnection of drill string and riser should take place within 5 minutes. If the drill bit and the drill string have to be pulled into the cased borehole before disconnection, additional time is needed depending on the open hole length. A drill string tripping speed of 500 m/hrs and 250 m open hole length, requires in addition, at least 30 minutes.

This master thesis will be based on the results achieve in the project thesis completed December 2010. A master student from the Department of Engineering Design and Materials will have focus on the steps in the product development process of the mechanical system. The discussion and evaluation leading to the final concept selection for mechanical detail design is expected to be written in collaboration

*Tasks:*

- Update and establish final boundary conditions
- Evaluate and select final concept (selected for detail design).
- Establish operational procedures based on limitations on existing rigs.

- Evaluate alternative control concepts. Several systems might be used. The concept will affect both operational reliability, accuracy and costs. Control and monitoring systems to be considered should be ( but not limited to):

    - Use of existing BOP control system.
    - Use of battery powered subsea hydraulic power unit with acoustic link to the surface vessel
    - Use of a separate system based on hydraulic conduit and electrical cable to the surface vessel
    - Accumulator based energy stored subsea with possibility for recharging using ROV. Acoustic link to surface vessel.
    - Others.

    The concept selected should take into consideration the overall operational reliability, costs and safety (HAZOP, RCM and FMECA analyses would be possible tools to be used in the evaluation process of the different concepts for control and monitoring).

Professor Sigbjørn Sangesland at the Department of Petroleum Engineering and Applied Geophysics is co-adviser for this master thesis.

The thesis must be written like a research report, with an abstract, conclusions, contents list, reference list, etc.

During preparation of the thesis it is important that the candidate emphasizes easily understood and well written text. For ease of reading, the thesis should contain adequate references at appropriate places to related text, tables and figures. On evaluation, a lot of weight is put on thorough preparation of results, their clear presentation in the form of tables and/or graphs, and on comprehensive discussion.

Two paper copies of the thesis are required. A CD with complete report should also be delivered to the department.

Starting date: 17th January 2011

Completion date: 14th June 2011
Handed in:

Trondheim 17th January 2011.

Magnus Rasmussen
Professor

# Preface

This report is written by Andreas Djupesland and represents the results conducted in the Master Thesis work in the Master of Science Degree at the Norwegian University of Science and Technology (NTNU) in the spring semester 2011. The assignment is written within the specialized field of Marine operation and maintenance technology at the Department of Marine Technology. The Master Thesis is the final product of the Master of Science Degree. It covers the workload of one semester and gives 30 credits.

The assignment was given by Sigbjørn Sangesland, Professor at the Department of Petroleum Engineering and Applied Geophysics. It was supervised by Magnus Rasmussen, Professor in the Marine operation and maintenance technology section at the Department of Marine Technology. Sigbjørn Sangesland has also functioned as a co supervisor on this assignment.

This report presents the possibility of utilizing conventional drilling vessels in the seasonable open waters surrounding the Arctic. The need for a reduction in the time associated with moving off and on location with the vessel is identified. Several solutions are presented and compared.

The Thesis is party written in collaboration with Trond Schou Moum, a master student from the Department of Engineering Design and Materials. The discussion and evaluation leading to the final concept selection for mechanical detail design of a concept, is written in collaboration. The need for a subsea control system is addressed and solutions compared.

I want to thank my two supervisors for good guidance and many helpfull coments on my work. Credit should altso be given to:

- Dr Paul A. Potter, Subsea consultant in Odfjell Drilling Technologies, for good advice and for helping me obtaining insight into procedues and relevant hardware.
- Several people in the Transocean Norway system should be recogniced for their help in obtaining spesifications, drawings etc.
- Bjørn Rudshaug in Aker Solutions, for data and info on Akers iron roughneck design process

I especially want to thank my partner Henriette for being patient with me and helping me on many levels.

Trondheim, June 3, 2011

Andreas Djupesland

# Abstract

The global energy demand is increasing. The oil companies are going into harsher climates and deeper waters to replace their reserves. Much of the undiscovered hydrocarbon reservoirs are believed to be located in the Arctic region. The seasonable ice free waters surrounding the Arctic can be drilled utilizing conventional drilling vessels designed for open water conditions. The region introduces several new operational challenges leading to an increased possibility of the drilling vessel moving off location.

This Master Thesis looks at the challenges related to operating a conventional drilling vessel in the seasonable open waters in the Arctic, using today's methods for disconnecting and reconnecting the marine drilling riser from the BOP.

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The operational subsea control system needs are mapped and several possible control options are presented and evaluated. Based on a Preliminary Hazard Analysis, cost and system complexity, a control system is chosen.

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# Abbreviations:

| | |
|---|---|
| AHC- | Active Heave Compensator |
| BOP- | Blowout Preventer |
| CCW- | Counter Clockwise |
| CW- | Clockwise |
| DDM- | Derrick Drilling Machine/ Top Drive |
| DP- | Drill Pipe |
| EDPHOT - | Emergency Hang off Tool |
| EDS- | Emergency Disconnection Sequence |
| HPU- | Hydraulic Pressure Unit |
| LMRP- | Lower Marine Riser Package |
| MODU- | Mobile Offshore Drilling Units |
| NCS- | Norwegian Continental Shelf |
| POOH- | Pull Out Of Hole |
| psi- | pound per square inch |
| RIH- | Run In Hole |
| SIR- | Subsea Iron Roughneck |
| STD- | Drill pipe stand. Pre made up length of drill pipe consisting of 3 equal drill pipes. |
| TJ- | Tool joint |
| WD- | Water Depth |
| WL- | Wire Line |
| WOW- | Waiting on weather |

# 1 Introduction

The International Energy Agency's World Energy Outlook 2008 projects a scenario of 45 % increase in global energy demand by 2030, and hydrocarbons to account for 80 % of the supply. The strategy they propose to meet these demands, is to recover hydrocarbons in three different ways (IEA, 2008):

- Improved recovery from currently producing reservoirs
- Development of low quality reservoirs (shale gas, oil sands, etc.)
- Map and exploit remote regions, i.e. deep and ultra-deep waters and harsh environments like the Arctic.

The Arctic region has an abundance of natural recourses in many forms. The US Geological Survey assessment of the region, states that hydrocarbons amount to 1669 trillion cubic feet of natural gas, 90 billion barrels of oil and 44 billion barrels of natural gas liquids. 84 % of these volumes are in deep water basins in the Arctic region (D. Gautier, 2008)

To reach these resources, we need to drill exploration wells. Drilling in this environment has been done previously, however this has up to now been in shallow waters and on a smaller scale.

The interest for the Arctic region in Norway, has recently increased after Statoil announced a major field discovery in well 7220/8-1 at the beginning of April 2011. This is a field called Skrugard and have had major press coverage in the spring of 2011. This well is located 110 km south of Bjørnøya, half way between the most northern part of mainland Norway and Spitzbergen.

The Arctic environments impose new operational as well as engineering challenges. One of the challenges is the increased probability of having too move of location with the drilling unit due to ice features drifting near the drill location. This in turn creates none productive time with a considerable increase in drilling cost as a consequence.

This thesis aims at mapping the challenge related to staying on location with a conventional drilling unit operating in the seasonable open waters in the Arctic. It will go through the current methods and practice for disconnecting and reconnecting the marine riser system to the blow out preventer located on the sea floor. The future need for a reduction in disconnection and reconnection time when moving on and off location with a drilling vessel will be addressed by presenting and rating several alternative concepts. The subsequent control system needs will be addressed and an analysis is undertaken to choose the favourable control system.

Previous work on this matter is limited to a project thesis written in 2007 by Therese Sønstabø as a student in the Department of Petroleum Engineering and Applied Geophysics at NTNU. This work does highlight some of the challenges related to arctic offshore operations. Her work does not conclude as to any preferred methods or in detailed solutions. The report also consists of the work undertaken by the author in his project thesis delivered in December 2010.

# 2 Operating mobile offshore units in the Arctic

To get hydrocarbons from the reservoir to the marked , a complete set of complex processes is needed. One of them involves the creation of the well by drilling. The water depth on well location will to a large extent govern the type of drilling unit used. Today the most common is to use a mobile offshore drilling unit (MODU). They are used in exploration, appraisal, intervention and production drilling. MODU's include semi submersibles, drilling barges, jack ups and drill ships. As the name implies, these units are capable of moving off location when the well is completed or the risk related to staying on location is too high.

In recent years the focus has shifted to meet the ever increasing energy demand. The oil companies are on the search to maintain their reserves. Some of these reserves are assumed to be located in the Arctic.

Drilling in the Arctic with MODU's is not a new venture and started in the mid 1970's north of Alaska. The Kulluk is a MODU and is shown in Figure 1. It was launched in 1983 (Rirzone, 2010) and operated in the waters north of Alaska to early 1990's in water depths from 20 to 60 meters. The vessel is designed to withstand ice loads from 1.2 meter of unbroken level ice in survival mode. Survival mode indicated that normal operation is halted and that the vessel can stay at location. The Kulluk is a drilling barge i.e. it has no propulsion and is dependent on towing vessels to change the drilling location. The hull is inverted conical with the main deck measuring approximately 100 meters in diameter and the waterline about 70 meter. The hull is omnidirectional i.e. it is independent of the ice angle of attack (Løset and Gudmestad, 2006). The inverted conical design is chosen to change the ice failure mode so that the ice is broken in bending instead of crushing.

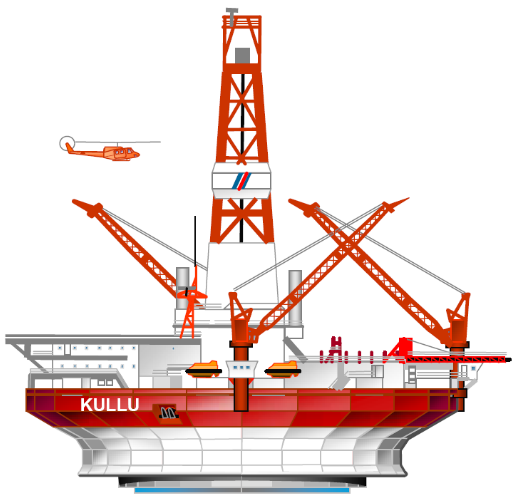


Figure 1: The Kulluk (Hewitt, 2007)

The Kulluk is designed to perform in ice conditions, however with its large waterplane area it becomes sensitive to heave and rolling motions when operating in open water. Conventional drilling unit designs are optimized to operate in ice free open water conditions with very good vessel motions allowing drilling operations to continue in rough weather conditions. These units are numerous and the day rates are lower compared to specialized vessels designed particularly for arctic operations.

The US Geological Survey has in a report published in 2008, given an assessment of undiscovered oil and gas in the Arctic. The probability of finding an oil or gas field with recoverable resources greater than 50 million barrels of oil equivalent is shown on a map given in Appendix 1. Combining this info with the Arctic marine topographic map given in Appendix 2, we see that some areas are located north of Russia in shallow waters and others are located in several waters on depths between 100-

2000 meters. 84 % of estimated hydrocarbon volumes are thought to be in deep water basins in the Arctic region. Wells drilled on locations deeper than 100 meters will be favourable to drill with the use of a semisubmersible or a drillship.

Based on the above the conclusion is that the marked for conventional semisubmersibles and drill ships is present, however the operating climate is different to what they are used to today.

## 2.1 The Arctic climate

The Arctic is a widely used term, defined in several ways. The most common is perhaps the Arctic Circle (66° 33′ 44″ north), which is the approximate limit of the midnight sun. This definition might not be adequate to describe some of the areas where we would find it beneficial. The Arctic is therefore often defined by the 10° Celsius isotherm in July, which also corresponds quite well to the northern three line shown in Appendix 3

Operating in the marine environment in the Arctic introduces several challenges due to the climate, such as:

- Sea ice
- Icebergs
- Logistics
- Safety issues such as relief well drilling capabilities
- Working condition such as long periods without daylight
- Low temperatures
- Permafrost
- Icing on vessel and on/in equipment
- Weather forecasting

In the following segments the main challenges related to the drilling vessel staying on location in the Arctic will be addressed.

### 2.1.1 Forecasting weather in the Arctic

Running large scale operations involving the interface between ocean, air and humans will always be weather dependent. At lower latitudes we have gained experience over several centuries with marine activities. Therefore statistical data is present and gives the opportunity to build numerical models used in the forecasting of weather. When planning offshore operations the result of these models is used to estimate weather conditions and to ensure that required safety margins are present.

The numerical models used for simulations today are optimized and fine-tuned to give a satisfactory prediction further south where the marked and the number of users is greater than in the north.

Observations are also used in forecasting of the weather, such as satellite observations, buoys, planes, radio probes, offshore structures, vessels observations and observations made on meteorological posts. The areas between these observations are blind spots where nothing is measured. In the Arctic, there is satellite coverage for observations; however the number of verifications by vertical observations like planes or balloon radio probes is not available to a satisfactory degree. The number of ground observations by ships etc., is also quite low. Feedback on received weather forecasts used to improve the models and future forecasts, is therefore not present to a satisfactory degree.

The sum of uncertainty and the physical environment means that smaller weather phenomena's, such as troughs can play a significant role on the ground, without being picked up and taken into account in forecasts. Troughs arise when cold air flows from the north, above the ice and meet the relative warm water masses along the ice edge. This introduces instability in the atmospheric conditions, which might build up wind, thunder and precipitation. Troughs have an average life span of 18 hours and can reach wind speeds of 20,8 to 32,5 m/s. Troughs can also play an important role in the initiation of larger weather system like polar lows (Samuelsen, 2010). Polar lows, are small scale and short lived atmospheric low pressure systems that occurs in the Arctic region. It can have a horizontal extent from 100 to 1000 km and have a life span from 6 hours to a couple of days. Polar lows are also called Arctic hurricane and have near-surface winds of at least 17 m/s (Rasmussen and Turner, 2003). However, troughs are 7 to 10 times more common than the more known polar low. In genera troughs can be seen as a smaller version of the polar lows. Both the troughs and polar lows can involve rapid change in wind direction and force.

As a rule of thumb, the Norwegian meteorological institute claim they can forecast polar lows and troughs quite accurate 0 to 12 hours ahead. Further 12 to 24 hours a decline in accuracy is observed. Beyond 24 hours they find it hard to forecast these phenomena's (Samuelsen, 2010).Therefore, in an offshore context we should not expect the same confidence interval in the Arctic as we do for example on the Norwegian continental shelf (NCS). MODU operations into the Arctic region should therefore expect weather forecasts with shorter time intervals and with a wider estimation uncertainty as compared to the standard obtained in areas where similar operations are being carried out today. The occurrence of rapidly changing wind conditions should be expected when operating in regions affected by troughs and polar lows.

### 2.1.2 Operating in ice

Challenges concerning floating ice features will arise when operating MODU's further north.
The focus in this work is to study challenges related to the use of conventional drilling vessels in the seasonal open water areas where hydrocarbons are present. Based on this, it is assumed that the vessel will not be constructed such that it can sustain ice actions as a result of ice features. This involves that the vessel will have to move off location if ice moves into its proximity.
Sea ice and icebergs are the main contributors to a possible disconnection and will therefore be described in the following sections.

#### 2.1.2.1 Sea Ice

Sea ice forms from salt water. The freezing temperature is approximately -1, 8° Celsius for sea water with 3, 4 % salt. At this temperature we might observe growth of frazil particles. The sea ice continue to grow as long as there is a large enough temperature difference to transport the heat from the underside of the ice into the cold air circulating above the initial ice level, thereby continuing the icing process beneath the existing ice.

The salt that is present in the seawater will to a large degree be separated away from the ice crystals when the ice is formed. However, some salt is isolated in the ice structure and remains locked in the ice. When such ice is exposed to a long period of freezing temperature, the ice will accumulate the salt into liquid salter water with lower freezing temperature. This liquid is called brine and can, given enough time, leak vertically downwards to form brine channels into the underlying seawater. Because of this, older ice can be measured with lower salinity level. Older ice normally means multiyear ice, i.e. ice that has survived the summer melting period and is exposed to multiple winters.

Due to the decreasing salinity of the sea ice with time, first-and multiyear ice can be distinguished with the use of satellite sensors. The satellites plots the difference in electromagnetic properties and a salinity based ice map can be turned into a first/multiyear ice map. In Figure 2 the end of February sea ice age map is shown.

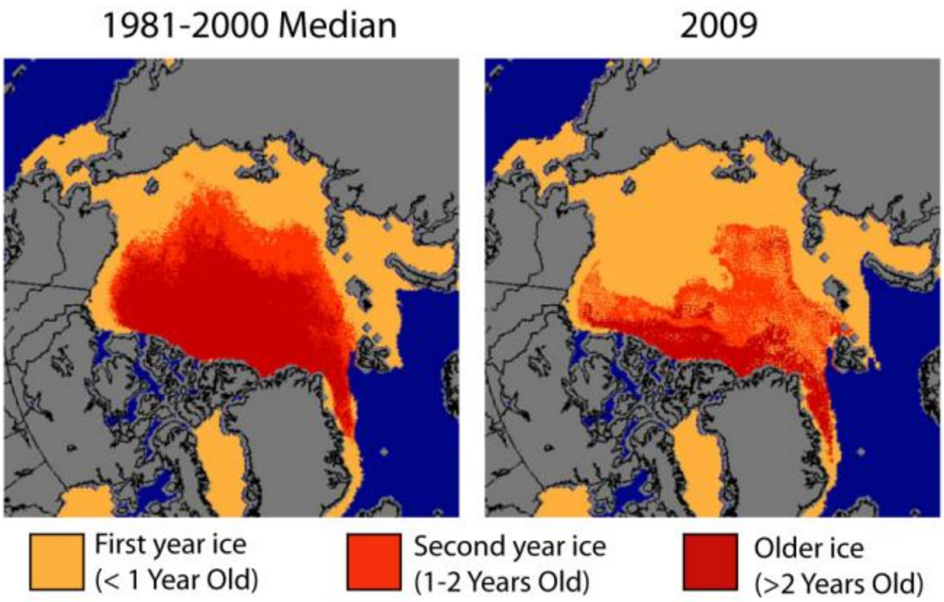



Figure 2: Map indicating the end of February ice extent (NSIDC, 2009)

Most areas containing only first year ice can be reached on a seasonable basis. This involves that hydrocarbons can be drilled for with conventional MODU's, however only in a limited time interval. These waters are called open operating environments. Typical locations referred to as open operating environments are:

- North, North- east Barents Sea
- Pechora Sea
- Sakhalin
- Chukchi Sea
- Baffin Bay

In these waters it will be possible to utilize conventional drilling vessels for operations depending on well completion time and operating conditions. The open operating environment does not mean that the waters will be completely ice free. On the contrary it indicates that ice will be present to some extent and must be taken into account when the operation is planned, I.e. the drilling vessel can withstand the ice actions, the ice is managed by standby support vessels dedicated for ice management or the drilling vessel has to be moved off location.

The opposite of open operating environment is a closed operating environment, reflecting the conditions where multiyear ice is present or there is a large flux of multiyear ice. The limits between the two ice regimes are not easy to determinate. They vary from year to year and on geographical location. Typical closed operating environment are:

- US Beaufort sea
- Canadian Beaufort sea
- Laptev Sea

Operating in these conditions requires ice strengthened designs in both drilling and support vessels. At present time, such vessels are not widely accessible in the price range that makes drilling economically favourable in large scale.

The differences between the two operating environments can have significant impact on the drilling, marine requirements, schedule and costs for operations (Hewitt, 2007).

#### *2.1.2.2 Drifting sea ice*

Wen operating in the open water area mentioned above, there is a possibility of encountering drifting ice features. Such features might originate from broken sea ice or fresh water glacier ice in the form of icebergs. Drifting ice might become a problem depending on its amount, size, speed, directions and drilling vessel design.

The driving forces behind ice drift are (NSIDC, 2010)

- Wind
- Ocean currents
- Coriolis force
- Internal ice stress
- Sea surface tilt

The wind is a significant contributor to the forces influencing ice drift. The wind driven ocean circulations in the Arctic are shown in Figure 3 (NSIDC, 2010). The two largest systems are the Beaufort Gyre rotating clockwise and the Transpolar drift flowing from the Russian Siberian cost towards North Greenland and the North Atlantic Ocean.

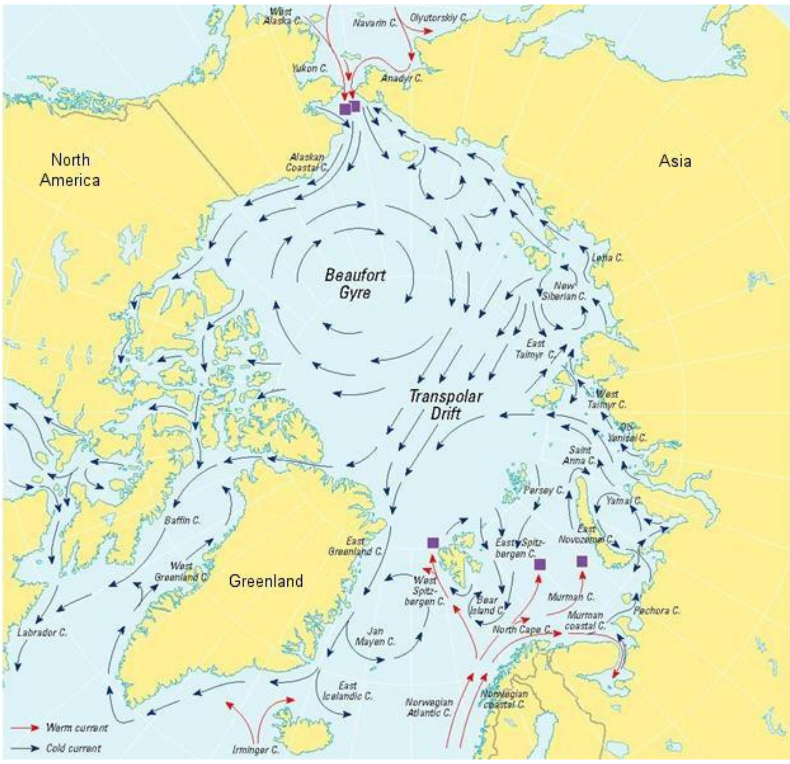



**Figure 3: Arctic Ocean circulations (NSIDC, 2010)**

The two systems are large contributors to the long term ice drift patterns shown in Figure 4. In this figure the drift is rendered as vectors, so that the speed and drift direction can be represented. It is important to bear in mind that these long term patterns can have large short term variations as a result of a storm or other metrological phenomena's as discussed in section 2.1.1 (NSIDC, 2010).

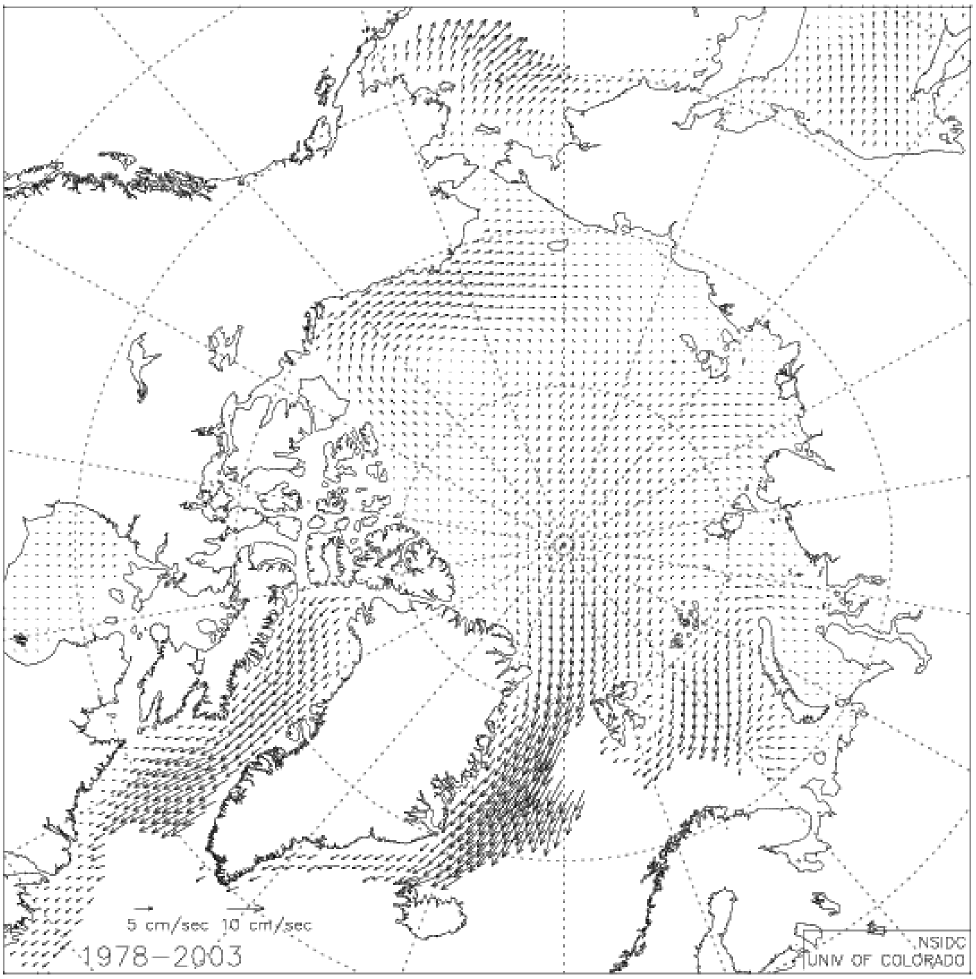



**Figure 4: Mean Arctic ice motion from 1978 to 2003 (NSIDC, 2010)**

#### 2.1.2.3 Drifting Icebergs

Icebergs originate from glacier ice. Glaciers are created when snow compounds on land and is compressed under its own weight. Given enough time and pressure, the snow is gradually converted into glacier ice. After enough ice buildup, the glacier will flow outwards to distribute its increased mass.

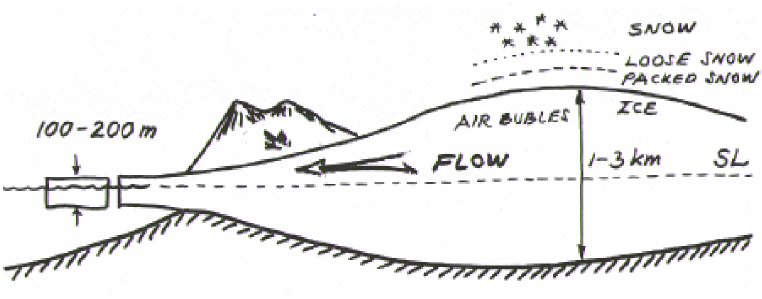



**Figure 5: Glacier and iceberg formation (UNIS, 2010)**

This flow is characterized by creep deformations, involving a low internal rate of change in the ice structure such that the ice appears plastic in its deformation.

Icebergs in the Barents sea are mostly formed on the shores of Franz Josef Land, however, icebergs are also created around Novaya Zemlya, the East side of Svalbard and Severnaya Zemlya (EB, 2010). The biggest contributor to icebergs in the Arctic is the Greenland icecap. The areas that are affected by iceberg drift from the Greenland icecap is shown in Appendix 4 .

Iceberg drift trajectories are affected by the same factors as drifting sea ice listed in 2.1.2.2. Additionally, grounding must be taken into account. Because of the relative large mass compared to other drifting ice features, the icebergs have a deeper draught. This leads to the grounding of bigger icebergs when they encounter shallower waters. Normally, large icebergs are not considered a problem in waters shallower then 50 meters (UNIS, 2010)

## 2.2 Operational consequence of operating a MODU in the Arctic

As presented in this chapter, the challenges linked to arctic offshore operations are diverse and multi-disciplinary. In this rapport the challenges are narrowed down to the vessels ability to stay on location connected to the subsea equipment using a conventional semisubmersible or drillship.

Looking at only this challenge and based upon:

- The areas where floating ice features are relevant versus the locations of the potential hydrocarbons
- The water depths making drifting icebergs possible
- The sum of uncertainties in weather forecasting
- Wind as a driving force in floating ice features drift

A conclusion is reached. An increased rate of disconnections must be expected if not the effort put into ice management is substantial. Ice management is performed by standby boats and includes towing, melting and vessel propeller thrust etc. in order to lower the probability of drifting ice features becoming a hazard to the operation. Ice management can only be done on features that are:

- Few enough
- Small enough
- Detected visually or by radar

Ice management is also an extra expense added to the well construction cost.

Based on this, the goal should be to minimize the need for ice management by being capable moving of location and on again without a considerable operational downtime.

# 3 The Marine riser system

Before establishing the disconnection procedure a basic understanding of the systems involved is needed. This chapter gives an introduction to the marine drilling riser system and some of its support systems.

The riser system forms an extension of the wellbore from the Blowout Preventer (BOP) stack to the drilling vessel, see Figure 6.The primary functions of the marine riser system are to (API16Q, 2001):

- Provide fluid communication between the well and the drilling vessel
  - In the riser annulus under normal drilling conditions
  - Through the choke and kill lines when the BOP stack is being used to control the well
- Support the choke, kill, and auxiliary lines
- Guide tools into the well
- Act as the load carrier when running and retrieving the BOP

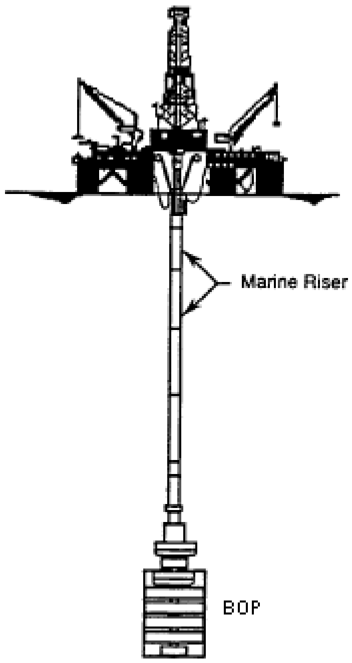


Figure 6: The marine riser system(API16Q, 2001)

The fluid that the riser transports can be sea water or in most cases oil or water based drilling mud. This is used to transport drill cutting, lubricate and cool down the drill bit. It also makes it possible to build the hydrostatical column which, together with mud specific gravity, produces the needed pressure to enclose the downhole pore/reservoir pressure.

A typical marine riser system consists of (McCrane, 2001):

- Riser joints
- Slip joint
- Upper and lower flex joints /ball joints
- Riser tension system
- Diverter system
- Lower marine riser package (LMRP)

The complexity and important role of the riser system in well control means that the system is under several API, NORSOK and classification society requirements. The riser system requirements are listed but not limited to:

| | |
|---|---|
| API | API spec 16R, API 16F, API RP 16Q, API BULL 16J, API SPEC 16F |
| NORSOK | NORSOK D-010 |
| DNV | DNV-OS-E101, DNV-OSS-302 |

Table 1: Riser rules and regulations

In the following sections an introduction to the different parts included in a marine riser system. A figure giving an overview over the components is enclosed in Appendix 5, this should be used as a reference to achieve overall system understanding.

## 3.1 Riser Joints

The riser consists of segments of steel pipe varying from 50 to 90 feet (15, 2 to 27, 4 meters) from flange to flange. A pipe segment is called a riser joint. The riser joint is made up by:

- Riser main tube
- Auxiliary lines
- Flanges

The riser can also be delivered in smaller lengths for adaptation to water depths etc. A smaller intermediate riser joint is called a riser pup joint and is delivered in customized lengths, depending on the customer's needs.

The riser joints are ended in matching flanges and can be made up/installed with bolts above the rotary table before they are lowered down and the next joint is inserted in the riser stack. The riser components are described in detail in the following sections.

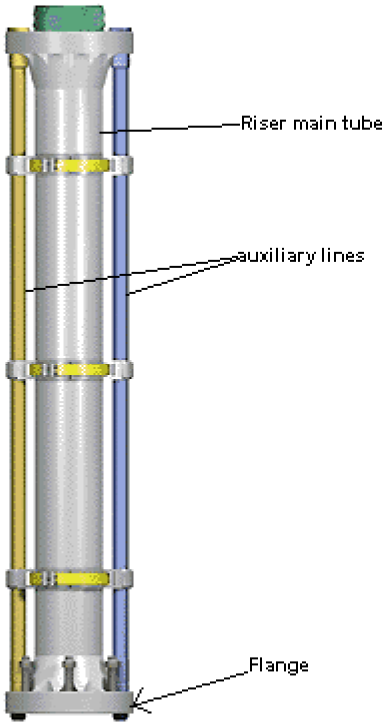



Figure 7:Cameron RF riser joint (Cameron, 2010)

### 3.1.1 Riser main tube

Riser main tube and associated couplings are generally sized to be compatible with a specific BOP stack size. Compatible BOP bore i.e., the BOP internal hole diameter, and riser outer diameter combinations are (McCrane, 2001):

| BOP [inch] | BOP[mm] | Riser OD[inch] | Riser OD[mm] |
|---|---|---|---|
| **13 5/8"** | 346.1 | 16 | 406.4 |
| **16 3/4"** | 425.5 | 18 5/8 | 473.1 |
| **18 3/4"** | 476.3 | 20 or 21 | 508 or 533.4 |
| **20 3/4"** | 527.1 | 22 or 24 | 558.8 or 609.6 |
| **21 l/4"** | 539.8 | 24 | 609.6 |

Table 2: Compatible BOP bore and riser outer diameter combinations

The main tube is specified by its outside diameter, wall thickness, and material properties. Steel grades most commonly used in risers are x-52, x-65 and x-80 where the number refers to the material yield strength in $10^3$ pound per square inch (psi). The most common material is the x-80 with a yield strength of 80000 psi equivalent to 552 MPa.

The riser tube pressure rating should sustain the load corresponding to the difference in hydrostatic pressure between the drilling fluid inside the riser and seawater outside in all operational conditions. In addition to this the riser main tube must sustain the loads from:

- Waves
- Current
- Applied dynamic tension while in operation and while running the BOP stack.
- Rig Motions

All these loads are dynamic, thus making fatigue toughness an important material and design quality that the riser must incorporate.

### 3.1.2 Auxiliary lines

These lines carry fluids along the length of the riser. Normally, they are an integral part of each riser joint and are attached on the outside of the riser main tube by support brackets. This is shown in Figure 7. These lines are used for the following (API16Q, 2001):

**Kill & choke**

The kill and choke are used to provide a controlled flow of oil, gas or drilling fluid from the wellbore to the surface when the BOP is closed.

The pressure rating should correspond to that of the BOP stack, normally 15000 psi

**Mud boost line**

When drilling in small diameter holes, the mud flow rate is reduced such that it is optimized for downhole performance. When the mud return flows into increased diameter channels like the riser, the mud flow velocity goes down. This might cause poor drill cuttings transportation and lead to build-up of cuttings downhole. In order to increase riser annular circulating velocities, we might use a mud booster line. The booster line guides drilling mud into the riser just above the blowout preventer stack in a riser pup joint fitted with a gate valve as shown on Figure 8.

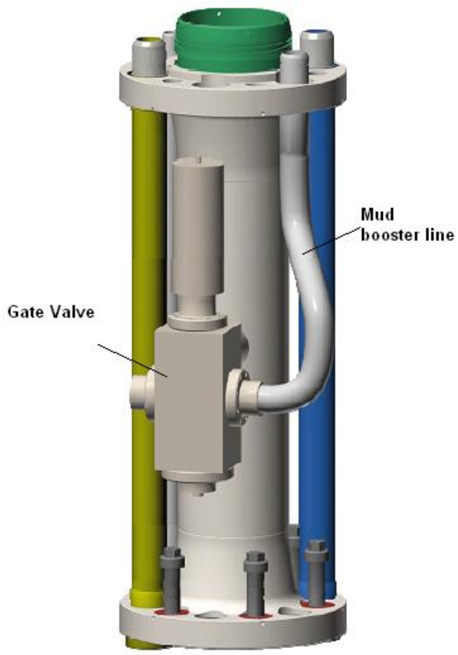



Figure 8: Mud booster pup joint (Cameron, 2010)

**Hydraulic Supply lines**

There is a possibility for the riser to be fitted with hydraulic supply lines that can carry hydraulic operating fluid to the BOP subsea control system. This is often the case when using a multiplex BOP control system, described in chapter 9.2.3

The pressure rating on the hydraulic supply lines should match the BOP control system pressure rating.

**Air lines**

If the riser is fitted with air cans to provide buoyancy, air will have to be supplied through air lines on the riser to adjust the applied buoyancy.

## 3.2 Drilling vessel motions

The drilling vessel is not a fixed structure and is therefore reacting to environmental loads by moving in a six degrees of freedom system shown in Figure 9.

A movement along one of the axes will lead to the vessel moving off location and thereby change the riser length and angle.

In addition, pitch and roll movements will create angular differences between the drill floor and BOP stack.

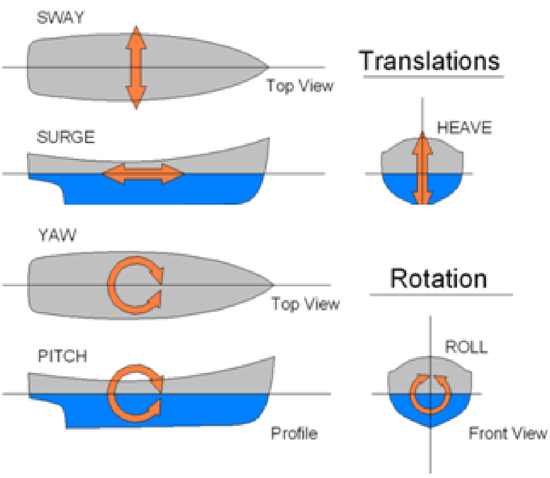



Figure 9: Vessel DOF (wikipedia)

In the following the parts that allow the riser system movements as described above, while still being able to fulfill the primary functions already stated in section 3, is presented.

### 3.2.1 Slip joint

Heave is the most common vessel motion in any sea state and a motion difficult to change once the hydrodynamic properties of a vessel is given .

In order to allow vertical movement, the riser system is equipped with a telescopic joint/slip joint. It has an inner and an outer barrel and is sealed with a packer assembly such that drilling fluid can flow back to the drilling vessels fluid handling system. On the slip joint shown in Figure 10, there is placed a tensioner ring where the riser tensioner wire ropes are connected. The packer assembly is located above the tension ring. This represents the top of the BOP mounted riser stack and indicates the fixed sea bottom level.

Figure 10 also shows the goose necks terminating the auxiliary lines from the riser over in flexible hoses. This provides a flexible transition of the auxiliary lines from the rig to the riser

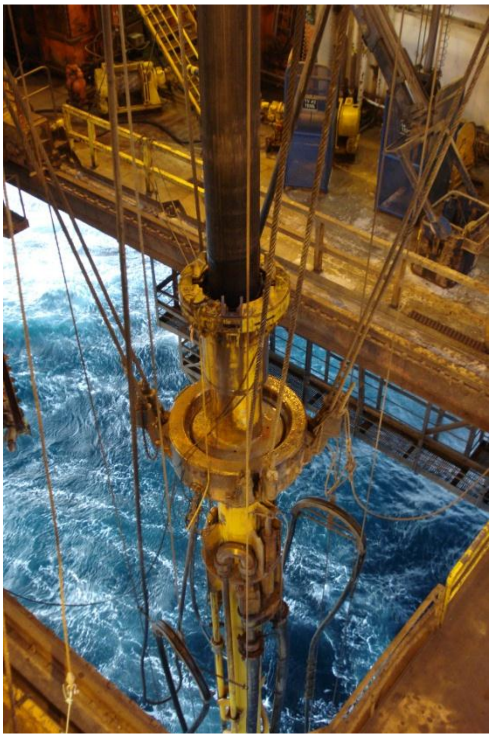


Figure 10: Slip joint (Djupesland, 2009)

### 3.2.2 Upper and lower flex joint

A floating drilling vessel might be moored or dynamically positioned. However, it does not stay centered perfectly over the wellbore. Current, wind, tides and waves act to push the rig off the ideal position. In order to prevent excessive bending loads in the riser, flex joints are used at the bottom and top of the riser assembly. The flex joint provides for typically $10^0$ of deflection of the riser as the rig moves horizontally, rolls or pitches above the well.

The rotational movement is achieved using flexiblel elements made up of in a sandwich of spherical steel rings and synthetic rubber. (McCrane, 2001). The design can also be of a ball-joint type. The ball joint will be hydraulically balance-pressurized to avoid excessive friction between the ball and the housing, thus reducing the friction. A ball joint is shown in Figure 12.

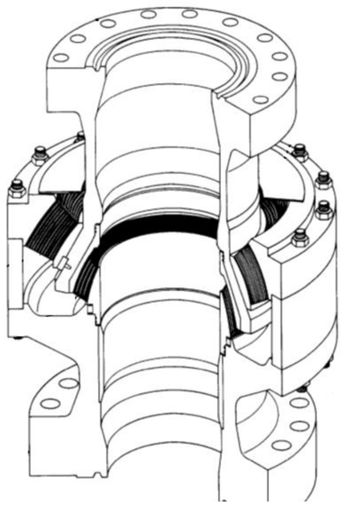


Figure 11: Flex joint (Transocean, 2010)

## 3.3 Riser tension system

The riser tension system is used to apply tension at the top of the riser. This is done in order to prevent the riser from buckling and to keep it in a close to vertical orientation. The tension is applied on the tensioner ring, which is located on the outer barrel of the slip joint, shown in Figure 10. The forces are transferred either by the use of hydraulic cylinders or wire ropes mounted on the tensioner ring. The wire rope system is the conventional solution and uses hydraulic cylinders fixed on the vessel to keep the desired tension in the ropes. Both systems are energized by a bank of high pressure air/gas accumulators and a gas/hydraulic interface. The riser tension system is an important parts of the riser disconnect sequence, as it picks up and lifts the entire riser system from the BOP when unlaced.

## 3.4 Diverter System

The diverter is located on top of the upper flex joint, directly below the rotary table at drill floor level. The system diverts the drilling fluid that returns with the riser to the flow line that goes to the mud treatment system onboard. It also has the capability to close an elastic packing around the drill pipe (DP) to divert a possible gas influx from entering the drill floor by routing it overboard for venting. A typical diverter is shown in red in Figure 12, where the elastic element is shown in red.

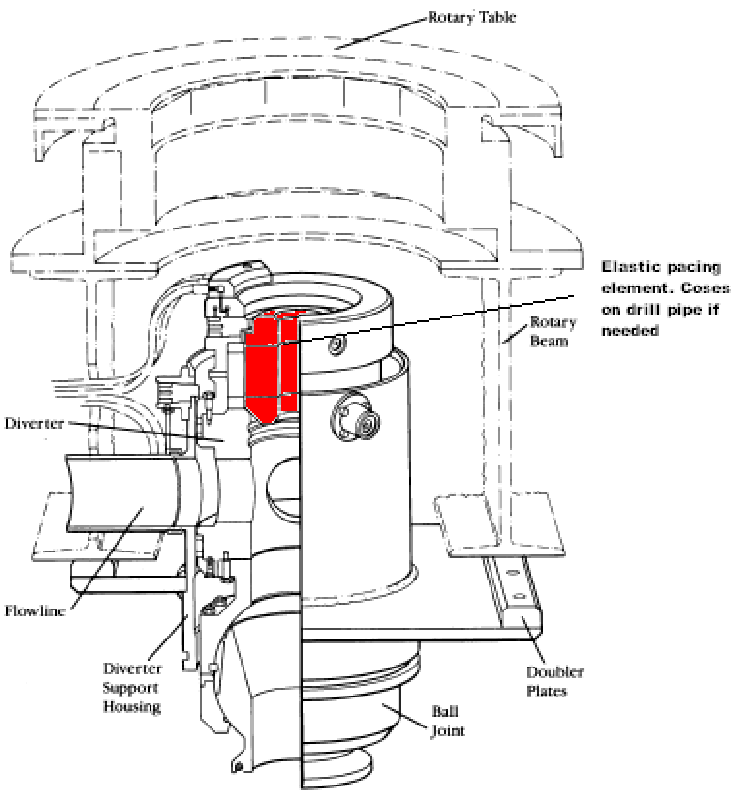



Figure 12: Diverter & ball joint assembly (McCrane, 2001)

## 3.5 Lower marine riser package

The lower marine riser package (LMRP) is the lower end of the marine riser system. It marks the transition from the riser system to the lower BOP stack. The LMRP consists of :

- Riser adapter
- Flex joint
- One or more annular preventer
- Hydraulic connector
- Control pods

This is shown in Figure 13.

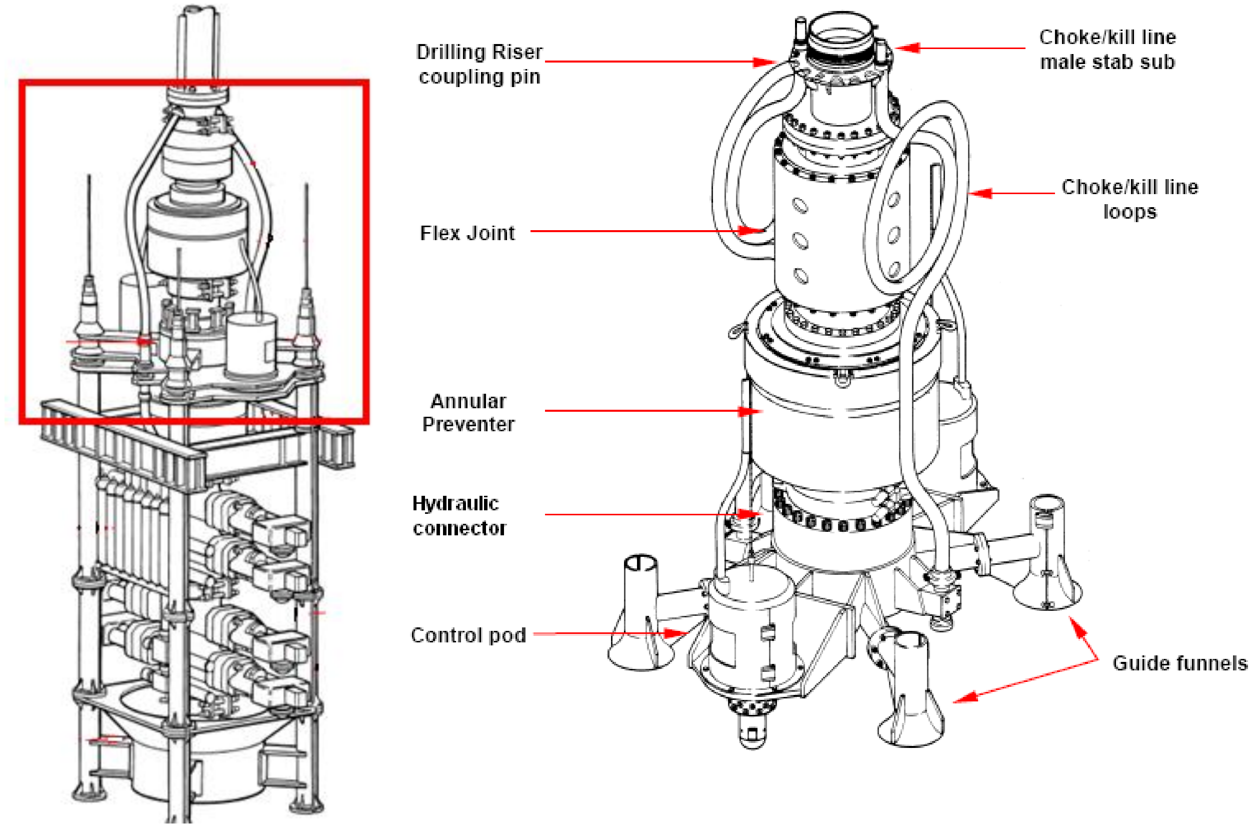



Figure 13: LMRP shown in red on BOP(left) and detailed view(right) (Vetco)

### 3.5.1 Riser adapter/Flex joint

The first part of the LMRP is the riser adapter which has a standard riser coupling flange. The adapter is fitted with auxiliary line kick outs to facilitate flexibility for the auxiliary lines over the flex joint. After the kick outs, the lines cross over into pressure hoses or steel pipe before they are continued to the lower BOP stack.

The next element is the previously mentioned lower flex joint/ball joint. In Figure 14 we can see an oil state/Cameron version where the riser adapter and the flex joint is one part.

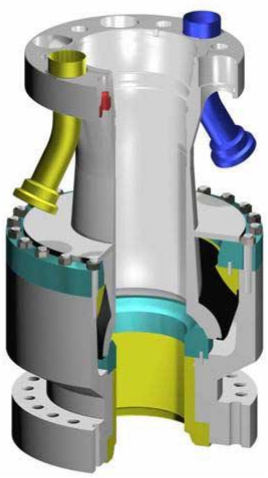


Figure 14: Riser adapter and flex joint (Transocean, 2010)

### 3.5.2 Annular preventers

The riser annulus can hold large quantities of drilling fluid with high specific gravity. The annular preventer must be able to close and retain these drilling fluids. They can close on drillpipe (DP), casing or upon itself. This is done by applying hydraulic pressure and pushing the rubber/steel insert out in the annulus. When the hydraulic pressure is vented, the steel inserts in the rubber help return the annular preventer to its initial position.

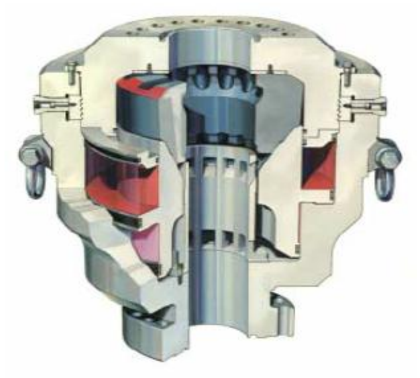


Figure 15: Vetco annular preventer (Vetco)

### 3.5.3 Hydraulic connector

The LMRP ends with a hydraulic connector securing the LMRP to the lower BOP stack. It is this connector that is opened under a controlled riser disconnect. Manufacturers include ABB Vetco Gray, Cameron DrillQuip etc. The connector is hydraulic driven and when pressure is applied on the correct ports the actuator ring is pressed downwards. The actuator ring in turn, pushes the collet fingers into the matching profile on the male connector profile on the lower BOP stack. The release force is larger than the locking force to incorporate a safety factor that increases the chance of disconnection.

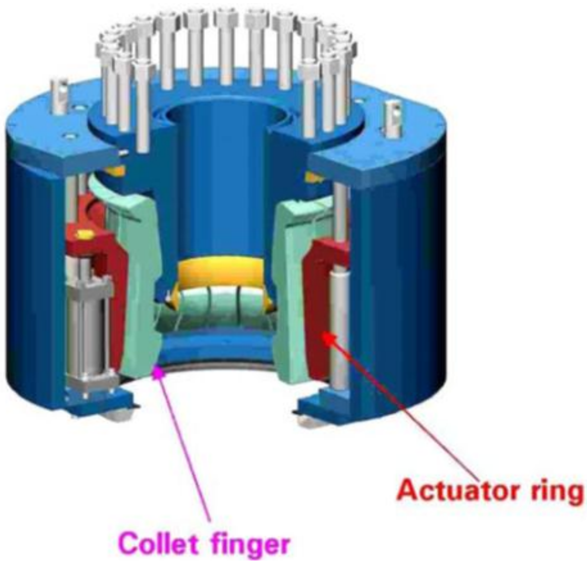



Figure 16: Cameron Mod 70 Collet Connector (Transocean, 2010)

If the drilling vessel has drifted far from well center, angular differences between the male and female parts and the connector is present. This in turn creates a possibility for a mechanical bind between the connector and the BOP male adapter. This can be a challenge and must be taken into account when designing the disconnect sequence.

The connector shown on Figure 16 is a Cameron mod 70 collet connector. The mechanical function is similar to other models/manufacturers.

When installing a hydraulic connector, a seal ring is installed between the female and male profiles. The seal rings come in different designs; however they are all based on the principle of delivering a metal to metal seal surface. Due to this, the ring must be exchanged every time the gasket is "disturbed", such as under a LMRP disconnection. This must be done with the use of a work ROV equipped with several special tools and a pressure test must be performed over the seal, to verify that no leaks are present. This is done by sealing the lower BOP with the use of a BOP test tool or by preinstalled test rams in the BOP.

### 3.5.4 Control pods

The LMRP is fitted with two male control pods that stab into female receptacles on the lower BOP stack. These control pods terminates the pod umbilicals supplying the BOP with control signals and hydraulic pressure. The dual setup is chosen to achieve redundancy so that if one pod/umbilical is rendered useless, the other is capable of controlling the entire BOP and LMRP. The umbilicals are clamped and fixated and are located 180° apart of each other. The control pods on the LMRP are also located 180° apart. The BOP control system is presented in more detail in Chapter 9.2.

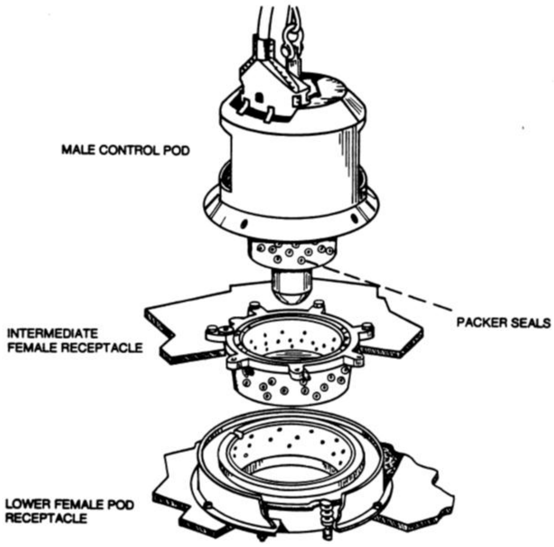



Figure 17: Control pod change transition(Vetco)

The hydraulic pressure and control signals are transferred to the lower BOP stacks female receptacle and to their final users via a hose bundle connected to the lower receptacle.

There are, as mentioned earlier, several hydraulic users on the LMRP. In the case of a disconnection we need hydraulic supply even after the lower BOP stack is de energized. This is done by use of an intermediate female receptacle fixed to the LMRP guide frame. This provides capability to use the annular preventer and the connector after disconnect and before reconnect (Vetco).

# 4 The Blow out preventer stack

The main function of the subsea blow out preventer is to maintain well control if the drilling operation encounter flux of reservoir fluids when penetrating layers of varying pressures. A sudden pressure peak and subsequent influx of reservoir fluid is also known as a kick. If this is experienced while drilling, the annular and/or ram preventers can be closed and drilling fluid with required qualities can be circulated in a controlled manner through the kill and choke line returning the well to normal operational condition. In a situation where the operation losses well control, the BOP is capable to shear certain tubulars and enclose the well pressure.

The BOP stack can be divided in two main parts. The upper part is the LMRP as previously described in section 3.5 and is actually a part of the riser system. The lower part is the BOP itself. It is the lower part that is left on the seafloor in case of a marine riser disconnect. It is also this part of the BOP that encloses the well pressure. This is often referred to as the lower BOP stack. The LMRP and lower BOP stack is shown in Figure 18: BOP stack (Vetco)Figure 18.

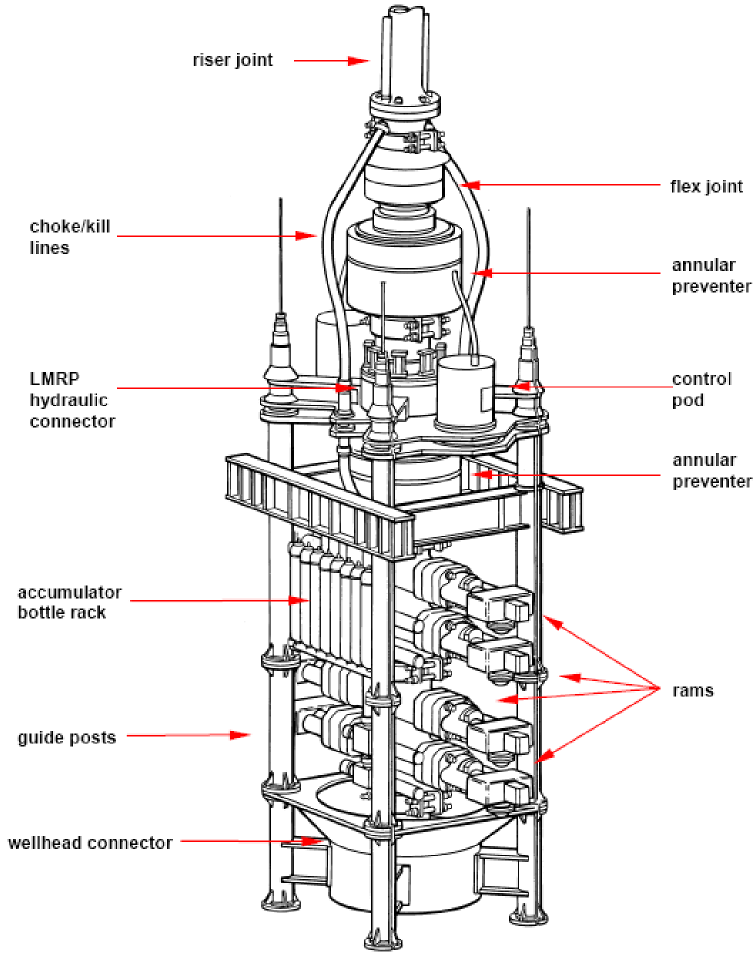



Figure 18: BOP stack (Vetco)

The lower BOP stack has the following main components:

- Welled connector
- A series of rams
- At least one annular preventer
- Male profile for the hydraulic connector on the LMRP to connect to

The annular preventer is similar in design and function as the earlier described annular preventer located in the LMRP and described in Section 3.5.2. The wellhead connector is also quite similar to the LMRP hydraulic connector in Section 3.5.3, the locking profile however, might have a different design and be able to transferee other loads.

The rams are hydraulic cylinders with the possibility of having different inserts fulfilling different needs. The main difference being pipe and shear ram. Common ram types will be described in the following section.

Figure 19: Fixed pipe ram (Transocean, 2010)

The pipe ram can have a fixed or variable pipe size design. The main function is to seal the annulus by closing on the DP, creating a pressure tight seal between the wellbore underneath and above the pipe ram. This is done to maintain control over the well while still using the DP to circulate drilling fluids. These rams can also be used for hanging off DP if required. The hang off capacity on the rams are different from the various manufacturers. The DP size being hanged off is also very important in relations to the hang off capacity. Shaffer (Nilsen, 2010), a producer of BOP systems, reports that for their multi ram models have hang off weight capacities according to Table 3.

| Bore Size (inches)<br>Working Press. (psi)<br>Model | Pipe<br>Size Range<br>(inches) | Pipe Suspension (in 1000 lbs.) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2 3/8 | 2 7/8 | 3 1/2 | 4 | 4 1/2 | 5 | 5 1/2 | 6 5/8 | 7 |
| **18 3/4, 15,000 SL** | 3 1/2–5 | — | — | 200 | 200 | 400 | 600 | — | — | — |
| **18 3/4, 15,000 SL/SLX** | 3 1/2–5 1/2 | — | — | 200 | 200 | 400 | 600 | 600 | — | — |
| **18 3/4, 15,000 SL** | 5–7 | — | — | — | — | — | 300 | 300 | 600 | — |

Table 3: Pipe ram hang off capacity

Based on this, an estimate of the minimal DP length capacity in the pipe ram can be calculated. If hanging off 6 5/8 , the capacity is 600 000 lbs on a 18 ¾” 15,000 SL model. This corresponds to a length of 6, 6 km of hung off pipe. This does not include the weight of drill collar, the bottom hole assembly or a safety factor and is based on a weight of 27,7 lbs./ft. (Gabolde and Nguyen, 2006)

Contrary to the fixed pipe ram, the variable pipe ram can adapt to several diameter drill pipes. The flexible elastomer sealing adapts with its steel elements to the particular DP in the hole at the time of activation. A variable pipe ram is shown in Figure 20

Figure 20: Cameron VBR (Transocean, 2010)

The bidirectional ram is a ram developed by Cameron and is designed to fulfill the demand for the required pressure testing of the hydraulic connector. As mentioned in chapter 3.5.3, the seal ring on in the connector must be changed after LMRP lift off. This is done prior to landing the LMRP. To verify that the correct sealing properties are obtained on the newly installed seal ring, a pressure test/
Leak off test is performed.

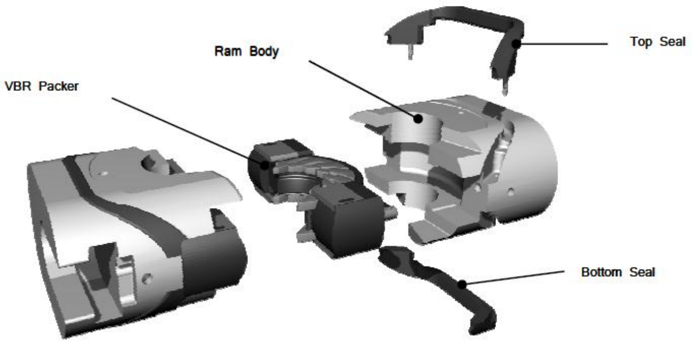



Figure 21: Bi directional test ram(Vidal, 2011)

The upper annular and the test ram are then closed, creating a confined cavity containing the connector and its seal elements. Not all BOP's are equipped with a test ram. If no test ram is installed, a BOP test tool must be lowered down inside the BOP i.e. run In hole (RIH) and landed in the BOP or wellhead to seal off the lower part of the bore.

The last type of ram is the blind shear ram. This ram cuts through DP and seals the wellbore. The blind shear ram is only used in emergencies. If sufficient time is present, the DP is hung off at a lower ram before the blind shear ram is used. Otherwise, the DP is lost down the wellbore and the potential well damages can be large. The shear ram cannot cut through DP tool joints. Consideration most therefore been given to insure that no tool joints are present in shear path of the shear ram when operated.

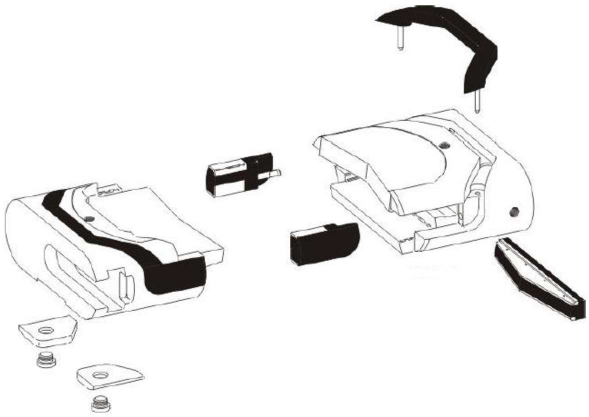


Figure 22: DVS shear ram (Transocean, 2010)

There are typically four rams in a normal BOP setup. The upper one will be a blind shear ram and the lower three usually pipe rams. The normal operating pressure is 1 500 /3000 psi, the shear ram however, usually has higher pressure sources to cut through the pipe. In Figure 23 we can see the upper ram shearing DP while the lower ram is used to hang off and seal around the pipe. A simplified functional BOP setup is also given in Appendix 6. The appendix also contains vertical heights of some components in relations to the wellhead. This height is of importance when considering forces transmitted from the riser system, through the BOP, to the wellhead.

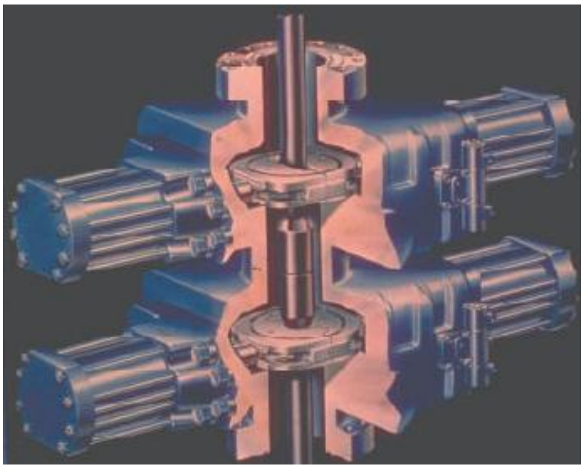


Figure 23: Ram's in function (Vetco)

# 5 Drill pipe

The disconnection operation includes the interface between rig equipment and drill pipe. This chapter therefore gives a short introduction to DP and different aspects related to drill pipe handling in the process of dis- and reconnection of the LMRP.

Drill pipe is a normally delivered in 31 foot length and is used in the drilling proses on and offshore. Drill pipe manufacturing is governed by the ANSI/API specification 5DP and is standardized concerning material properties and dimensions. It is important to bear in mind that the standard only covers API DP, there are also other designs available on the marked, with variations in treads, sealing and therefore also make up torques.

Drill pipe is the tool used to:

- Transfer the rotational torque to make hole, from the topside mounted top drive to the drillbitt on the other end of the drill string.
- Transfer the total weight of the drill string (which is made up of a number of single drill pipes, bottom hole assembly, drill collar etc.)
- Transport the well control fluid, chemicals and cement down to the allocated downhole position.

Normally DP is delivered in sizes from 2 3/8" to 6 5/8" for use in offshore drilling processes. The size difference is large both in dimensions and forces required to hold and make up the needed connection torque.

The DP consists of the DP body which in turn defines the DP dimension. In addition to this, there is a box and a pin end tool joint welded on to the pipe endings. See Figure 24 for details.

The threaded connection that connects two different DP's is located on the tool joint (TJ). The threads are API tapered threads providing a fast engagement in order to save operational time when making/braking up connections. The sealing effect is obtained by the shoulder-to-shoulder sealing surfaces, sealing the inner DP cavity from the exterior and gives a safe way of handling the other loads carried through the pipe body.

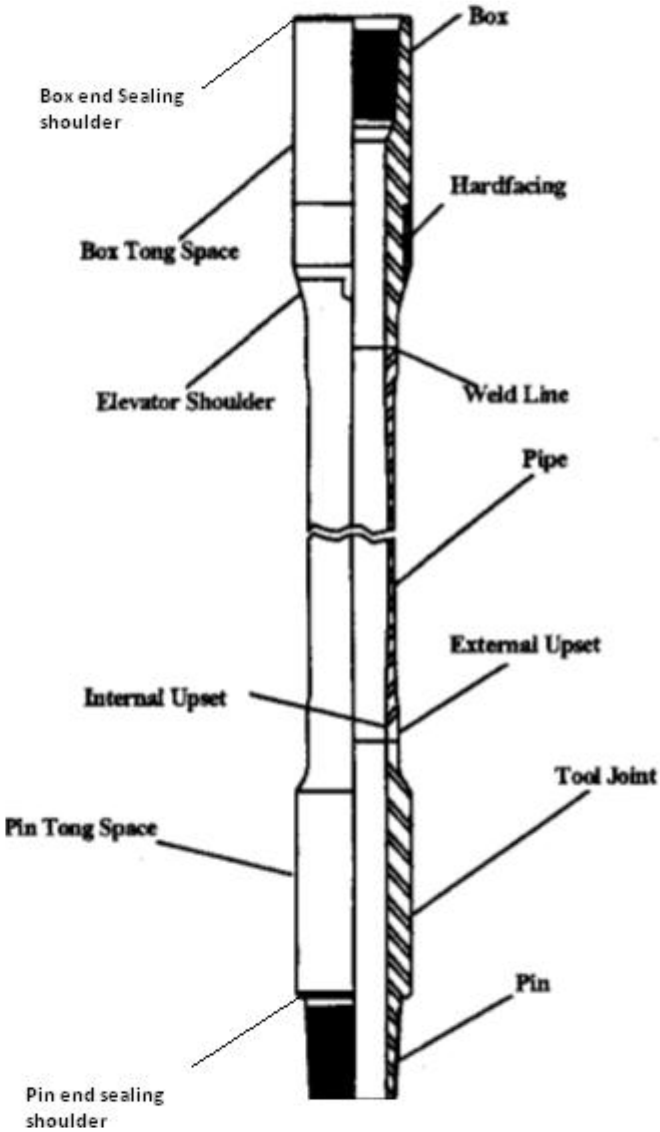



Figure 24: Drillpipe(API, 2010)

The elevator shoulder, hardfacing, sealing shoulder and tong space is also located on the TJ

The elevator shoulder is shown in Figure 25 and is a diameter transition with a standardized angel of 18° (box) and 35° (pin) (API, 2010). This shoulder is used when handling pipe with elevators by the drilling crew. It is used to fixate and to some degree carry the vertical loads when lifting drill pipe assemblies.

The hardfacing is also known as hard banding and is a hardened material belt laid down/welded on the box end of the DP. The hardened material belt is 3" wide and is raised up from the rest of the tong space by 1/16". This makes the tool joint more capable of withstanding operational wear and tear. The hardfacing is highlighted in red on Figure 25.

The tong space is the vertical section of the box and pin end of the TJ allocated to have rig tongs/iron roughnecks connecting to them and transferring the recommended make up/brake out torques. This area cannot be as hard as the hard facing area, as the gripping mechanisms would start to slide when applying high torques, destroying both the TJ and the rig tools.

Drill pipe length is measured from shoulder to shoulder and might vary within limitations stated in the buyer contract. Each drill pipe shall be measured, and the findings must be documented. API specifies that the accuracy of measurement technique used when recording DP length shall be within 0, 03 meter(API, 2010). This requirement introduces varying DP length. If a drillstring consist of several hundred single DP's, the length offset might be in the range of meters. It is therefore difficult to predict accurately where downhole TJ is located in a hang off/shear situation. Caution should therefore be taken with regards to lowering speed when landing TJ's on a pipe ram or similar mechanism.

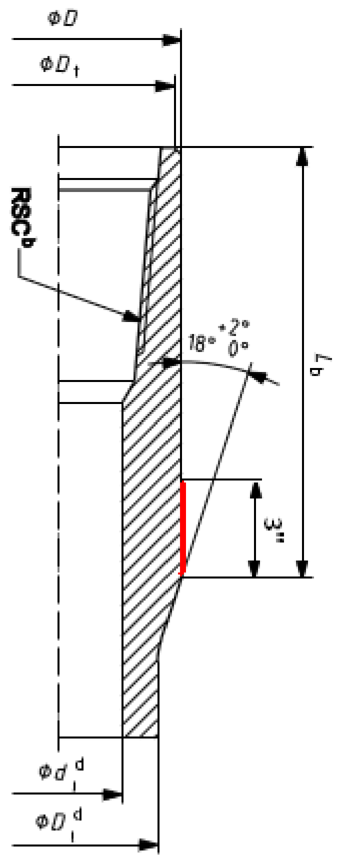



Figure 25: Box end Elevator shoulder, hardfacing in red (API, 2010)

The drill pipe often becomes worn out in the threads due to numerous make up and break out operations. The DP owners can refurbish the treads by machining new ones. As a result of this the TJ becomes shorter. This introduces the possibility of varying TJ length. The available reduction is controlled by API and NS-2 which is a drillstring inspection standard. Reference is made to Moum thesis where the extent and effects of the variation in TJ length is explained.

Drill pipe is mad by several manufactures including Grand Prideco and Vallourec Mannesmann to name a few.

# 6 The disconnection

The decision to disconnect the marine riser system from the BOP is mainly based upon operating criterias stated in the rig specific procedures. These procedures have to be in compliance with the governing national requirements on the location the drilling vessel is operating. Typical things affecting riser disconnection, might be:

- Vessel motions
- Vessel offset
- Tension in the riser system
- Angle of the lower flex joint
- Tension in the highest loaded mooring line

On the NCS the Norwegian maritime directorate has set regulations that all floating drilling and production vessels have to be in compliance with. This is known as "*The regulations for mobile offshore units*". Paragraph 16 under the production plant regulation it is stated:

*"The maximum excursion of the facility in the intact condition and after any single failure or double fault shall not exceed the maximum excursion that risers are designed to withstand. A safety margin of 2.5% of water depth shall be used for rigid risers, whilst a safety margin of 5% of the water depth shall be used for flexible risers" (Sjøfartsdirektoratet, 2003)*

The lower ball joint described in Section 3.2.2 is often mechanically limited to 10°. Based on this and including the 2,5% safety factor, the maximum vessel offset with regards to the riser system, is listed in Table 4:

| Water Depth (m) | Maximum offset (m) |
|---|---|
| **100** | 15,1 |
| **200** | 30,3 |
| **300** | 45,4 |
| **400** | 60,5 |
| **500** | 75,7 |
| **1000** | 151,3 |
| **1500** | 227,0 |
| **2000** | 302,7 |

Table 4: Maximum offset

If a drift off happens during normal drilling operations it is necessary to be able to:

- Hang off drill pipe on the pipe rams
- Shear the DP
- Seal the wellbore
- Disconnect the LMRP
- Clear the BOP with the LMRP

This needs to be completed before the limitations stated by the Norwegian maritime directorate are reached. Otherwise, damage to the wellhead, the BOP or losing the riser are possible outcomes. All are critical components in controlling the well. Effort is therefore put into modelling the actions needed to complete the disconnection in order to estimate the time used on a vessel specific level.

Traditionally the offset distance as a function of water depth (WD) has been used to establish watch circles to indicate the drift off situation, as shown on Figure 26. A yellow alarm is typically given at a drift off of 2,5 % of WD followed by a red alarm at 5,5 %(Robinson, 1997).

These limitations are in most cases correct. However, drilling in deep water and with heavy mud can result in a different riser performance and therefore change the riser system limitations.

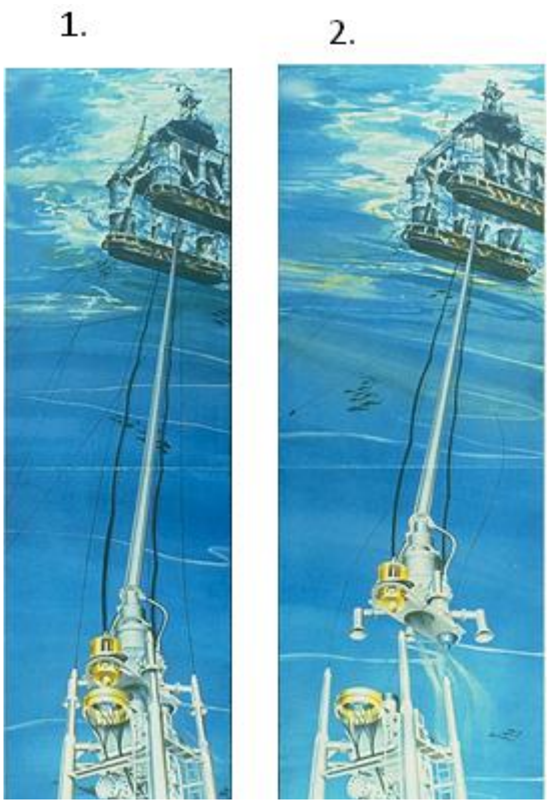



**Figure 27: The disconnection seen from a subsea perspective, LMRP lift-off to the right(Cameron)**

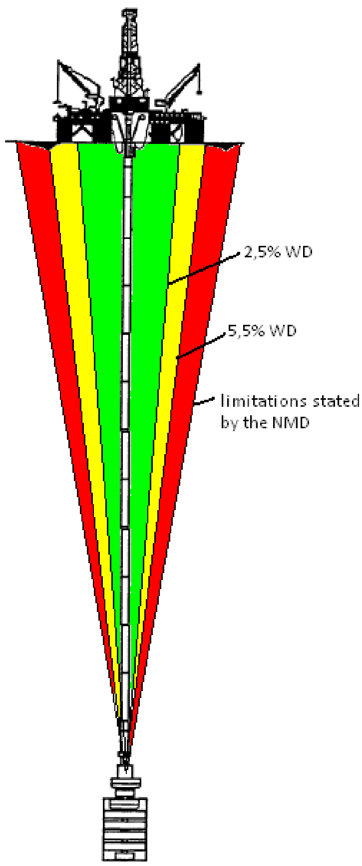



**Figure 26: Watch circles**

Based on this some rigs use lower flex joint angle as a improved indicator of whether to disconnect or not. An angle of 3° on the lower flex joint would typically indicate a yellow alarm and 5 ° a red alarm (Robinson, 1997). However, lower flex joint angle is not a standalone indicator. As seen from Table 4, large drift of values are encountered while operating on deep water wells. The elongation of the riser system must be compensated by the slip joint, thus making slip joint stroke a limiting factor on deeper waters.

A combination of the two measures in real time should give an improved indication on the riser trends and therefore the criticality with regards to an imminent disconnect.

If the vessel is approaching the offset limitations, the crew onboard will:

- Reduce chain tension on leeward side
- Adjust tension on wind side to equal levels
- Use the azimuth thrusters, which either might be operated manually from the bridge/control room or automatically by the mooring system if equipped as such.

If the situation continues to worsen after above measures are implemented, a disconnection is executed. A disconnection is shown in Figure 27, where we can see the LMRP clear the BOP and hang from the riser after the disconnection.

The reason for vessel drift off is in most cases weather induced forces but is not limited to this. Other factors might be:

- Dynamic poisoning system failure
- Mooring system failure
- Level or broken ice forces
- Collision with object
- Dynamic positioning operator fault

## 6.1 Current procedures for disconnecting marine drilling riser

If the disconnection take place while drill pipe is downhole, the operation has three choices. They can be simplified to:

1. Running emergency hang off tool and hanging off the DP on a pipe ram below the shear ram or in the wellhead
2. Hanging off the DP on a pipe ram and shearing the DP
3. Shearing the DP, dropping it into the well

All of the above methods seals off the wellbore and maintains the existing barrier philosophies. The difference is the time it takes to execute the complete set of preparations, operative tasks, the consequences for the well and the time it takes to become operative once the riser is connected to the BOP stack again Table 5 give a time estimate based on a well located on 300 meter WD. The disconnect time includes all tasks from normal drilling to liftoff of the LMRP from the BOP. The reconnect time includes the tasks undertaken from the LMRP is connected to the BOP and pressure is equal in riser and wellbore, until normal drilling operations is started up again.

| Disconnection method | Disconnect time | Reconnect time |
|---|---|---|
| **Emergency hang off tool** | 3 hrs. | 8 hrs. |
| **Hanging off the DP** | 90 sec. | 24-48 hrs. |
| **Shearing the DP** | 60 sec. | 48 hrs. at best |

Table 5: Disconnect/reconnect time (Lund, 2010)

The methods are described in detail in the following sections.

### 6.1.1 Use of drill pipe hang off tool

Most regions of the world have reliable weather forecasts and preparations can be made to upcoming situations that might include a disconnection. If severe weather is expected or other factors lead to the vessel operator expecting the operational limitations to be exceeded, Preparations to use the emergency drill pipe hang off tool can be started.

The emergency drill pipe hang off tool (EDPHOT) is a drill string that is designed to be hanged off in pipe rams or in the wellhead, its protectors or in the casing hanger.

The tool consists of a drill string and a tool joint box, this TJ box is equipped with two sets of internal threads on two separate faces. One of the treads is right hand threads like the rest of the DP threaded connections, and the other one is lefthander threads.

In Figure 28 we can see the:

1. Running tool
2. Hang off tool
3. Retrieving tool

Both the running and retrieving is done with the use of standard DP above the EDPHT. The tool is therefore made up as a part of the drill string and run in hole. When placed at hang off location the top drive applies a clockwise (CW) torque, releasing the running tool from the hang off tool. The drill string is then retracted into the riser and the riser can be sealed off. Beyond this point it is normal to wait in order to see if the situation continues to develop in the direction of a disconnection. In Appendix 7 a detailed operating procedure is given (Lund, 2010). In short, the following actions will have to take place:

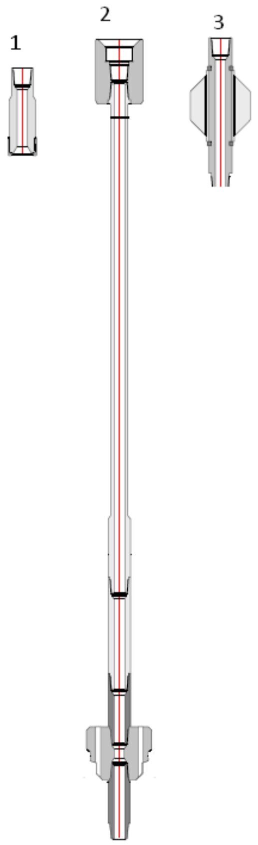



Figure 28: Emergency Hang off Tool(Cameron)

1. Pull bit inside last casing
2. Pull out of hole (POOH) a distance equal to the WD plus two stands
3. Install Kelly cock (valve that is made up in the DP string, in open position) with back pressure valve on top in one stand. Run in hole.
4. Install EDPHOT with one stand (three drill pipes, already made up in to one length) DP
5. Run hang off stand into one stand above BOP
6. Activate active heave compensator (AHC). Run in and land EDPHT in wear bushing/bore protector, set down weight underneath land of point.
7. Unscrew landing string
8. Pull out of BOP with landing string and close middle pipe-ram and blind shear ram.
9. Displace riser to sea water with the use of kill, choke and booster lines
10. Wait on weather to initiate disconnection of LMRP if necessary

The complete procedure must be completed before facing the operating limits. If the approach to these operating limits is slow, the time lost on waiting on whether (WOW) might be substantial.

There is also a chance for the disconnection not being initiated, In this case significant time that could otherwise be used for well productive tasks, is lost.

The time used to install an EDPHOT is depending on the distance from where the drillbitt is drilling to the last casing and the WD. If we look at deepwater drilling, time used on tripping out and into the hole cannot be neglected. A tripping speed of 500 meters per hour can be used Based on this assumption, the time used to run and operate the EDPHOT on a well at 300 meters WD is approximately 2 hours. Including one hour in handling of the tool, the total time is 3 hours. Time used on reconnection is due to extensive tripping, estimated to 8 hours before normal drilling can resume.

#### 6.1.1.1 Deeper waters

If we consider a well located on substantial deeper waters, say 3000 meters, the costs will increase. On such wells the drilling window might be narrow. This means that the difference between the inherent formation pore pressure and the pressure the formation can withstand without taking structural damage is small. This may lead to more challenging well control situations due to the formations pressure sensitivity.

Based on this assumption and due to the large wellhead /ram hang off profile as shown in Figure 28, the speed while Running in Hole (RIH) with the tool might be restricted by the operator. This will render our assumption of 500 meters per hour, as to high, and adds time to the preparations towards a planned disconnect. This added time might be substantial on deep and ultra-deepwater wells.

When running in hole with a the large diameter wellhead profile shown in Figure 28 the bottom hole pressure may vary. This is the result of the wellhead profile having a velocity in the relatively high viscous drilling mud. The pressure build up on the leading edge may account for too large variations in the bottomhole pressure if the tripping speed is too high and might therefore be restricted by the well operator.

If we estimate the restriction to a mean tripping speed of 200 m/hour and look at the well located at 3000 waterdepth, the time used will be:

1. Pull bit inside last casing
2. Pull out of hole (POOH) a distance equal to the WD plus two stands at 500m/h
$$\frac{3060\ meters}{500\ meters/hour} = 6{,}12\ hours$$
3. Install Kelly cock (valve that is made up in the DP string, in open position) with back pressure valve on top in one stand. Run in hole.
$$0{,}5\ hours$$
4. Install EDPHOT with one stand DP
$$0{,}5\ hours$$
5. Run hang off stand into one stand above BOP following operators restrictions of 200m/h
$$\frac{3030\ meters}{200\ meters/hour} = 15{,}15\ hours$$

6. Activate active heave compensator (AHC). Run in and land EDPHOT in wear bushing/bore protector, set down weight underneath land of point.

$$0{,}5\ hours$$

7. Unscrew landing string
8. Pull out of BOP with landing string and close middle pipe-ram and blind shear ram.
9. Displace riser to sea water with the use of kill, choke and booster lines
10. Wait on weather to initiate disconnection of LMRP if necessary

We are then able operational ready to disconnect the LMRP, if the situation requires this. We have then used a total of 22, 77 hours to reach the point where we are able to disconnect the LMRP.

The reconnection is somewhat wider in the time estimate due to larger uncertainties but due to the long restricted tripping distance and possible challenges, it is assumed to take 26 hours.

It should be noted that the estimates based on this specific ultra-deepwater well, is an extreme case. However, in general, both the disconnection and reconnection time will increase with wells that are located in deeper waters.

#### 6.1.1.2 Operational log review

In February 2011, Transocean Winner performed a DP hang off procedure with a subsequent LMRP disconnection. This was while drilling a well for Marathon oil in the southern part of the North Sea, well 24/9-10 A on the NCS. The operational log is enclosed in Appendix 10 to Appendix 12. As seen, the background for the disconnection was the anchor tension exceeding the operational limit stated for the rig as a result of wind and current forces. Going through the details in the log uncovers that significant time is on WOW, as a result of running the EDPHOT. After the deciding to RIH with the EDPHOT at 10:00 Friday 4/2-11 , we wait until to Saturday 5/2-11 at 05:45 before initiating the LMRP disconnection. A total of 19 hours and 45 minutes used on WOW.

### 6.1.2 Hanging off the drill pipe on a pipe ram and shearing the drill pipe

If there is a need to disconnect, but not sufficient time to run the EDPHOT, the DP is hung of in the pipe ram in the BOP stack. The pipe above the hang off point is sheared using the blind shear ram. Typically the vessel is in yellow zone when this procedure is relevant. The following tasks must be undertaken to be able to disconnect the LMRP:

1. If time displace riser to sea water
2. Activate AHC
3. Space out tool joint to be approximately 2 m above middle pipe ram
4. Close middle pipe ram with reduced pressure. 500 psi
5. Set down 5 tons on ram, increase pressure to 3000 psi
6. Set down string weight minus the weight above the BOP. Use some over pull when cutting the string
7. Cut the string using the shear ram

8. Pull out of BOP with the string. Close blind shear ram while pulling out of riser with DP and prepare to disconnect the LMRP

This process in much quicker in the EDPHOT disconnection sequence, however, it is challenging during the reconnect phase. This is due to the challenges associated with picking up the sheared DP. It might need extensive milling and fishing before pickup can be initiated. The milling and fishing operations exposes the subsea equipment for additional hazards, thus increasing the allover operational risk.
A disconnection time of 90 seconds and a very variable reconnection time of 24 hours might be expected.

#### 6.1.3 Shearing the drill pipe dropping it into the well, emergency disconnection

Shearing and dropping the drill string, is performed in extreme emergencies when facing a high risk scenario. In this process, there is not sufficient time to land the TJ in the pipe ram and the DP is dropped into the wellbore after shearing. This will typically be when the vessel has entered the previously mentioned “red zone”. It is normal practice to organize this procedure of emergency disconnection in what is called an emergency disconnection sequence (EDS)

The EDS shall be designed such that the well is safely shut in as a part of a functional sequence. The time the sequence takes is measured from the operator pushes a dedicated button and initiates it onboard the vessel, to the LMRP is lifted clear of the BOP stack. This time should be as short as possible. (API16D, JANUARY 2005) The EDS increases the process efficiency and minimizes human error in disconnections. The sequence can be reprogrammed between wells. There can also be several sequences available for the operator, thus making it more adapted to the ongoing well operation (Cameron).

The complete disconnection process takes normally somewhere between 30 and 90 seconds. If we look at the time spent before disconnection of the LMRP, this is the fastest method. Shearing and dropping the drillstring is a last resort decision and the consequence of this method will be prolonged reconnection due to DP fishing and milling, at best. However, the well can be severely damaged or lost completely in a worst case scenario due to the consequences of the dropped DP. The estimated reconnection time is 48 hours. This estimate is highly uncertain, as the damages due to the dropped drill string might be severe.

## 6.2 Cost of operational downtime

It is concluded in section 2.2 that we can expect an increase in disconnection frequency when constructing wells in arctic waters using conventional MODU's. In Chapter 6.1, the operational downtime time experienced, using disconnecting methods available today is estimated. Based on this, the costs related to disconnections can be estimated. It should be noted that the possibility of a disconnection is now based on a conventional MODU operating in Arctic waters where floating ice features are expected; with minimal ice management. The assumed possibility of the different types of disconnections is presented in Table 6:

| Method | Possibility/well |
|---|---|
| **Use of drill pipe hang off tool:** | 0,5 |
| **Hanging off the drill pipe and shearing** | 0,1 |
| **emergency disconnection** | 0,01 |

Table 6: Possibility disconnection/well

A well construction completion time of 55 days is assumed. This gives a yearly production of 6.6 wells. Based on this, the yearly amount of disconnections is estimated and presented in Table 7:

| Method | Possibility*well/year | Number of yearly disconnections |
|---|---|---|
| **Use of drill pipe hang off tool:** | 0,5*6,6 | 3,3 |
| **Hanging off the drill pipe and shearing** | 0,1*6,6 | 0,66 |
| **emergency disconnection** | 0,01*6,6 | 0,066 |

Table 7: Yearly amount of disconnections

The times used on the different methods are previously stated. Assuming a drilling vessel day rate of 500 000 $/day (20833 $/hour) we then can calculate the estimated cost of operational downtime due to disconnections using the time estimates stated in chapter 6.1. This is presented in Table 8 and Table 9:

Well at 300 meters water depth:

| Method | Number of yearly disconnections | Yearly disconnections*The sum of disconnect and reconnect time *day rate | Yearly cost related to disconnections in dollars |
|---|---|---|---|
| **Use of drill pipe hang off tool:** | 3,3 | 3,3*(2+8)*20833 | **687 489** |
| **Hanging off the drill pipe and shearing** | 0,66 | 0,66*24*20833 | **329 995** |
| **emergency disconnection** | 0,066 | 0,066*48*20833 | **65 999** |
| **Yearly total** | **4,026** | | **1 083 483** |

Table 8: Cost of operational downtime due to disconnections; 300 m WD

Well at 3000 meters water depth:

| Method | Number of yearly disconnections | Yearly disconnections*The sum of disconnect and reconnect time *day rate | Yearly cost related to disconnections in dollars |
|---|---|---|---|
| **Use of drill pipe hang off tool:** | 3,3 | 3,3*(22,77+26)*20833 | **3 352 883** |
| **Hanging off the drill pipe and shearing** | 0,66 | 0,66*24*20833 | **329 995** |
| **emergency disconnection** | 0,066 | 0,066*48*20833 | **65 999** |
| **Yearly total** | **4,026** | | **3 748 878** |

Table 9: Cost of operational downtime due to disconnections; 3000 m WD

In this comparison the relatively quick disconnection time of the hang off and shear and EDS methods, are baked into the uncertainty of the reconnect time. The time used waiting in weather can amount to a considerable number of hours; this is however neglected in this calculation, in order to get a conservative estimate.  It should also be noted that the estimate done on the deepwater well is an extreme high cost case and will not be representative on the NCS. With this in mind it is concluded that the cost associated with disconnections due to arctic operations amounts to 1.083.483 $/year for one rig operating on midwater wells and 3.748.878 $/year on ultradeepwater wells.

As for the operational log we can estimate that if we use a conservative standby day rate of 350.000 $, a 19 hours and 45 time slot amounts to a 288.000 $ loss for the operator. This is time that could have been used for well productive tasks as the weather limitations at the time, was not in existence of the operational limits before early on the morning of Saturday the 5/2-11. Reference is given to chapter 6.1.1.2 for the background info and Appendix 10 to Appendix 12 for operational details.

# 7 Alternative methods for quick disconnection of marine drilling riser

The oil and gas industry has in the last couple of years started to move into both more hostile environments and undertaking ultra-deepwater drilling. Looking at both planned and unplanned disconnections, there are improvement possibilities. Valuable time is used both related to the disconnection and reconnection phase.

Previous work within the topic (Sønstabø, 2007) mentions the possibility of placing components dedicated for making and braking tool joint connections, in the lower BOP stack or in the riser system. In order to introduce components reducing the time consumed, several design requirements must be fulfilled. In this chapter the design criteria's will be stated and new concepts for drilling riser disconnection will be presented. The emphasis will be on operations where DP is present trough the BOP stack.

## 7.1 System requirements

When designing a new concept as an integrated part of a complicated system, care must be taken with regards to the design requirements. In addition to the high system complexity, the system in question is placed subsea, out of reach and out of sight for the operating crew and maintenance staff.

The main design intent that the equipment must fulfill, can be summarized as:

- Locate and fixate the specific tool joint in question
- Remove TJ connection torque to a desired value with required accuracy
- B of minimal disturbance to the ongoing operation when not in use

All of the above must be performed:

- Safely, as an integrated part of the subsea equipment
- Within a desired time window
- With high operational reliability
- At a low cost
- With the ability to communicate with and monitor the subsea sequence

A more detailed study of the design requirements will be given in the following sections

### 7.1.1 Locating drill pipe

The tool joint can be located subsea using various methods. Acoustic, magnetic and mechanic localization have been addressed in this research to this thesis. The method chosen in the end was mechanical localization in the form of landing the 18° elevator shoulder on the box end of the tool joint, on a tool joint locator. This is shown in Appendix 18. This method is chosen due to low system complexity and it's similarity to methods used in the industry today.

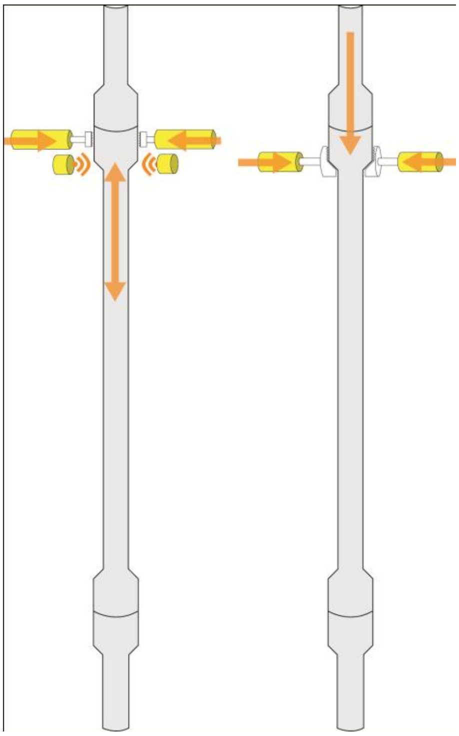


Figure 29: Magnetic and mechanic localization of TJ

In the process of de-torqueing a TJ, the weight of the drillstring and all downhole equipment is at all times held by the lifting equipment onboard the vessel i.e. the drawwork. Due to heave motions, the AHC system is activated under the entire process. The AHC system is designed to compensate for load variations, however, due to hydraulic losses, mechanical wear etc., vertical force variation in the range of 1-2% might be expected. This variation in vertical load must be taken up by the mechanism that grips the specific tool joint in question. Maximal vertical load is therefore assumed to be 30 tons and must be handled both in the positive and negative vertical direction to cope with load variations while the cylinders are clamped on the TJ.

### 7.1.2 Make up & break out torque

The torque needed to make or break TJ connections, vary with DP size and design. Technips Drilling Data Handbook is assessed as the best way to ensure sufficiently accurate make-up and break-out values. The recommended make-up torque varies between 45 270 - 70 870 Nm for 5 1/2" drill pipes and 59 530 - 88 090 Nm for 6 5/8" DP. It should be noted that these numbers apply to new TJ's, lower make-up torques are recommended for Premium class and Class 2 TJ's.

According to Aker Solutions, (Rudshaug, 2011) an addition of 5-10 % to the tabulated make-up torque has to be expected when breaking out the TJ connection. This is due to stick friction in the TJ threads and seal shoulder. The amount of stick friction is highly dependent on the condition of the threads, the cleanliness of the threaded area and the amount of thread-dope applied. Aker also estimates that all torque is applied over the first 15-30$^{0}$ of rotation from when the shoulders on the box- and pin end touch. After the shoulders touch, Hooke's law becomes applicable. This assumption is illustrated as a torque turn graph in Figure 30. All of the data from Aker Solutions is based on empirical experience gained through extensive testing in the process of building topside iron roughnecks. Using their experience is more realistic than assuming and calculating values from scratch. Adding a safety margin of 10% to the tabulated torque means the maximum torque needed is 15-20% above the tabulated torque from the Drilling Data Handbook ,when including the addition due to stick friction. This gives a maximum break out torque of 105 708 Nm. This is backed up by

NORSOK D-001’s nominative data sheet (NORSOK, 1998). This document recommends to install an iron roughneck with a minimum break out torque of 100 000 Nm and a make-up torque of 80 000 Nm.

Splitting the wanted 30$^o$ rotation into two 15$^o$ iterations simplifies the design of our product and minimizes the physical size of the torque mechanism. The assumed torque turn graph when performing two 15 $^o$ operational cycles is shown in Figure 30.

It should be noted that the torque case shown here is a worst case scenario considering a new 6-5/8” TJ. The makeup torque will decrease with degrading TJ condition and with smaller DP sizes.

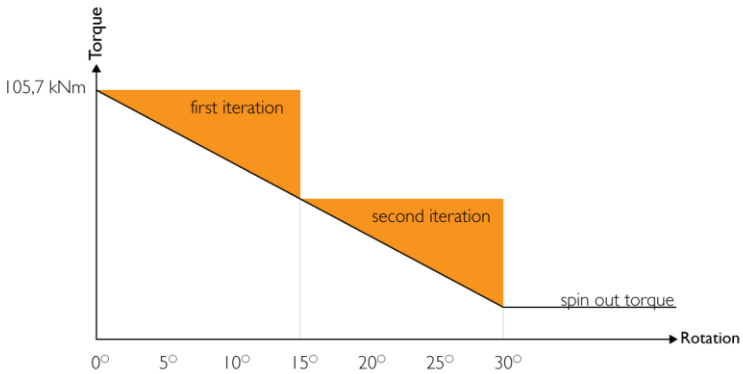



Figure 30: Assumed torque turn graph showing our two de-torque sequences

### 7.1.3 Clamping force

A dice is an interchangeable hardened machined component that is pressed into the softer TJ tong space material. A generic dice setup can be seen in Figure 31. These dices transfers the torque from a torque mechanism to the TJ connection. This is the same principle used by several topside roughneck vendors. The dices ability to transfer a torque is dependent on the force that the dice is pushed radial towards the tong space on the TJ. This force is called clamp force and ensures that the dices penetrate the tong space of the tool joint and therefore generating a friction factor of $\mu$ =1. The clamp force needed to sufficiently penetrate the tong space of the TJ with the dice is applied by using clamp cylinders. When choosing this clamp force it is s also essential to avoid using excessive force. This may lead to excessive pressure on the threaded area and thus increasing the stick friction and cause unnecessary penetration of the tool joint damaging the tong space.

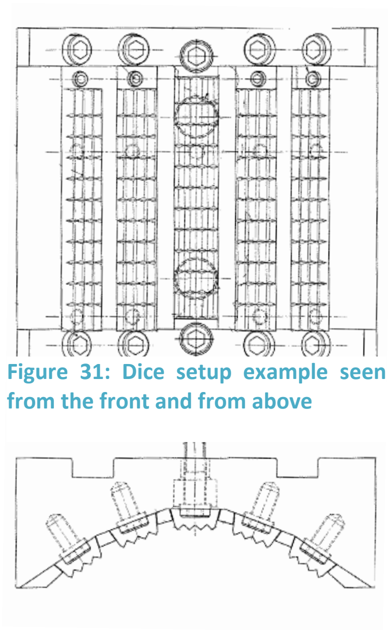


Figure 31: Dice setup example seen from the front and from above

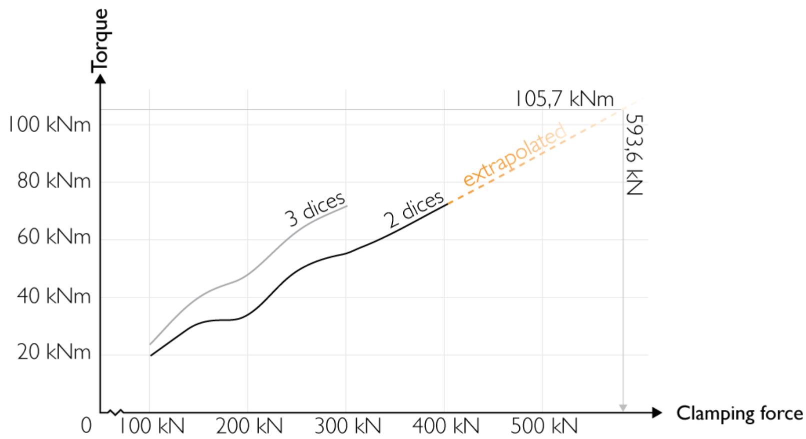



Figure 32: Aker Solutions clamp torque graph for 6 5/8" DP

The clamping force is highly dependent on what kind of torque that needs to be achieved. Aker Solutions has supplied empirical test curves for 5 ½" and 6 5/8" drill pipe, showing the relationship between needed clamping force and the torque this clamping force can provide without slipping i.e. relative rotational movement between the dice and the TJ. The "two dices" curve is the one valid for our design. This curve is extrapolated to find the approximate amount of clamping force needed in our design. The extrapolation is by no means exact, however, it is considered to be more exact than any calculation based on theoretical assumptions. The values from the Aker Solutions graph is the result from real tests done on real tool joint, and the clear tendency of the graph justifies the linear extrapolation as long as sufficient margin of safety is added. Using the same 105 708 Nm break out torque found in section 7.1.2, a clamping force of 593,6 kN is needed. As advised by Aker Solutions, 15 % safety margin is added to the read value to ensure the connection does not slip and deprave the tong space. This resulting in a clamping force of 682,7 kN

### 7.1.4 Riser forces

When considering a new component to be inserted as a load bearing element in the BOP or riser stack, the load across the component is of high importance. A conservative estimate of the expected loads in such an element is needed to look at the resulting stresses in its load bearing parts. This is executed to identify bad conceptual design at an early stage. Basing the design on a worst case scenario for a riser joint is therefore the design assumption. This is not the forces experienced while in operation, nevertheless, this conservative approach is capable of amplifying bad design qualities.

Ambrose compares traditional hang-off of risers in reference to a "soft" method (Ambrose, 2001). Traditional “hard hagoff” is performed when disconnecting the LMRP from the BOP. The diverter assembly is then removed and the slip joint is collapsed. The upmost part of the riser system is then retracted on board the drilling vessel and landed in a riser spider. This riser spider locks the rigid riser to the vessels, forcing the subsea system to obtain more or less the same vertical movements as the vessel. The resulting riser forces as a result of the two distinct methods are shown in Figure 33. This situation imposes large vertical forces and might lead to bending of the riser. This is important to take into consideration due to the fact that the machine might be integrated into the riser string and must survive all operational situations. Ambrose considers a hard hang off performed on an ultra deepwater level of 10 000 feet with rough weather.

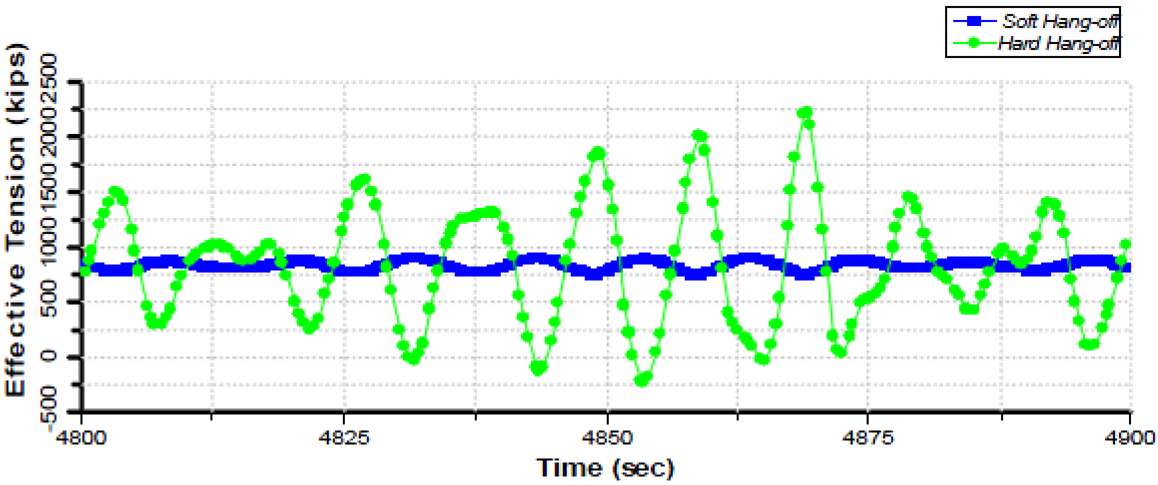



**Figure 33: Effective Tension Variation at Tension Ring, Hard vs. Soft Hangoff Small Drillship in 22-ft Hs Seas, 60 deg heading to the waves, 9600-ft Water Depth(Ambrose, 2001)**

The work undertaken in the article "Mooring and Riser Management In Ultra-Deep Water and Beyond" considers the forces involved when landing the BOP on the well-head for the first time (Pelley, 2005). This is the maximum static load the riser string is exposed to, as the BOP can weigh up to 500 tons. The study compares the use of conventional steel marine drilling risers with new composite marine drilling risers in ultra-deep waters, where the weight of the riser string can be a problem.

The study takes into consideration

- Weight of the BOP
- Weight of the LMRP
- Weight of the flex joint
- Dynamic heave amplitude
- Acceleration of the total weight (start and stop of lowering procedure)

This results in the following weights:

- 687 tons Static hanging wet weight
- 175 tons Hook load dynamic amplitude
- 98 tons Acceleration load
- 960 tons Total landing load

Conclusively, the work carried out by Ambrose combined with the results obtained by Pelley, gives us an estimate of handling 1000 tons. This is used as a requirement for the loads the product needs to handle vertically between two riser flanges. This load is calculated for the worst case scenario i.e. the riser that will have to carry all of the loads associated with the complete subsea system. This will, in a hang off situation, be the top part of the riser with the forces being reduced when going further down in the riser stack. This gives a conservative estimate of the forces applied on the product. It is also important to clarify that the forces mapped here are not detailed enough to perform an in depth design of the components. It is more a way of ranking how the different designs deals with the stress and strain as a result of the forces and to give an indication as to what range the forces will be in.

A more detailed force analysis, including fatigue study of the design must be undertaken on a later stage, in order to improve load bearing characteristics and give a favourable end design.

### 7.1.5 Dimensional requirements

Introducing new components in a subsea system will require careful planning. This includes building the design into the already installed equipment assemblies with minimal negative implications to existing operational and handling procedures and equipment performance. This is not an easy task, as the requirements are many and diverse. In this section the physical handling and installation restrictions that exist on relevant rigs for operation in and close to ice infested waters will be mapped.

#### 7.1.5.1 Background

The world's fleet of MODU's consists of a number of different designs. Deciding the physical layout of the rig is done in the early phase of construction and under later modifications and upgrades. These decisions are based on the operational requirements that are given by the operator. Such requirements may be:

- Type of operations
- Cost
- Design water depths
- Conceptual design
- Design generation
- Climate and other environmental conditions

The diversity in these aspects, give large variations in the physical buildup of the units. This should be taken into consideration in the conceptual design loops, too insure physical handling capabilities and to guarantee a large market basis for the design. The physical restrictions will be apparent in the following operations:

- Running an retrieval of equipment
- Installation in riser/BOP stack
- Shipping to and from vessel
- Carry out required planned and corrective maintenance
- Modifications to existing equipment

All the above mentioned operations will require physical handling of the equipment and the interface between the vessel physical limitations, crew banksmen and onboard lifting equipment. The first requirement is enough space on the MODU, both in height and width, to perform the mentioned operations.

A normal layout of a drilling unit will easily facilitate cargo handling to and from shore with a supply ship. From the supply ship there will be manual crane handling with cranes situated onboard the drilling vessel. Normally there will be space to lay out the equipment on deck for temporary storage and inspection.

The most challenging part of the physical handling will be the installation and running/retrieval process. This will have to take place in one of the most cramped and restricted parts of the rig namely the cellar deck area and the drill floor. The two areas have different limitations and will create two different running procedures.

If we choose to design the component to be installed on cellar deck, a draft of a running procedure will be:

1. Install components in cradle on top of lower flex joint on the BOP while in storage location on cellar deck.
2. Skid BOP with components out under the center of the drill floor.
3. Connect first riser flange to the components and run the entire length of the stack as before.

If we choose to design the component to be installed on the drill floor, a draft of a running procedure will be:

1. Skid BOP without components out under the center of the drill floor
2. Run components through the rotary on drill floor and connect to riser flange on lower flex joint
3. Connect standard riser to upper riser flange on components and run the entire length of the riser as before

The differences in design limitations between the two running procedures are large and a more detailed description of these areas is therefore given before selecting one installation and running philosophy.

### 7.1.5.2 Cellar deck

The Cellar Deck refers to the lower deck of a floater and will normally be the deck where crew and subsea engineers work when inspecting and maintaining the BOP stack. This area will be situated around the opening in the lower deck of the structure known as the moonpool. In Figure 34, the cellar deck can be seen within the blue box with the moonpool in the center of the figure. In this figure, the upper decks, drill floor and the derrick has been removed.

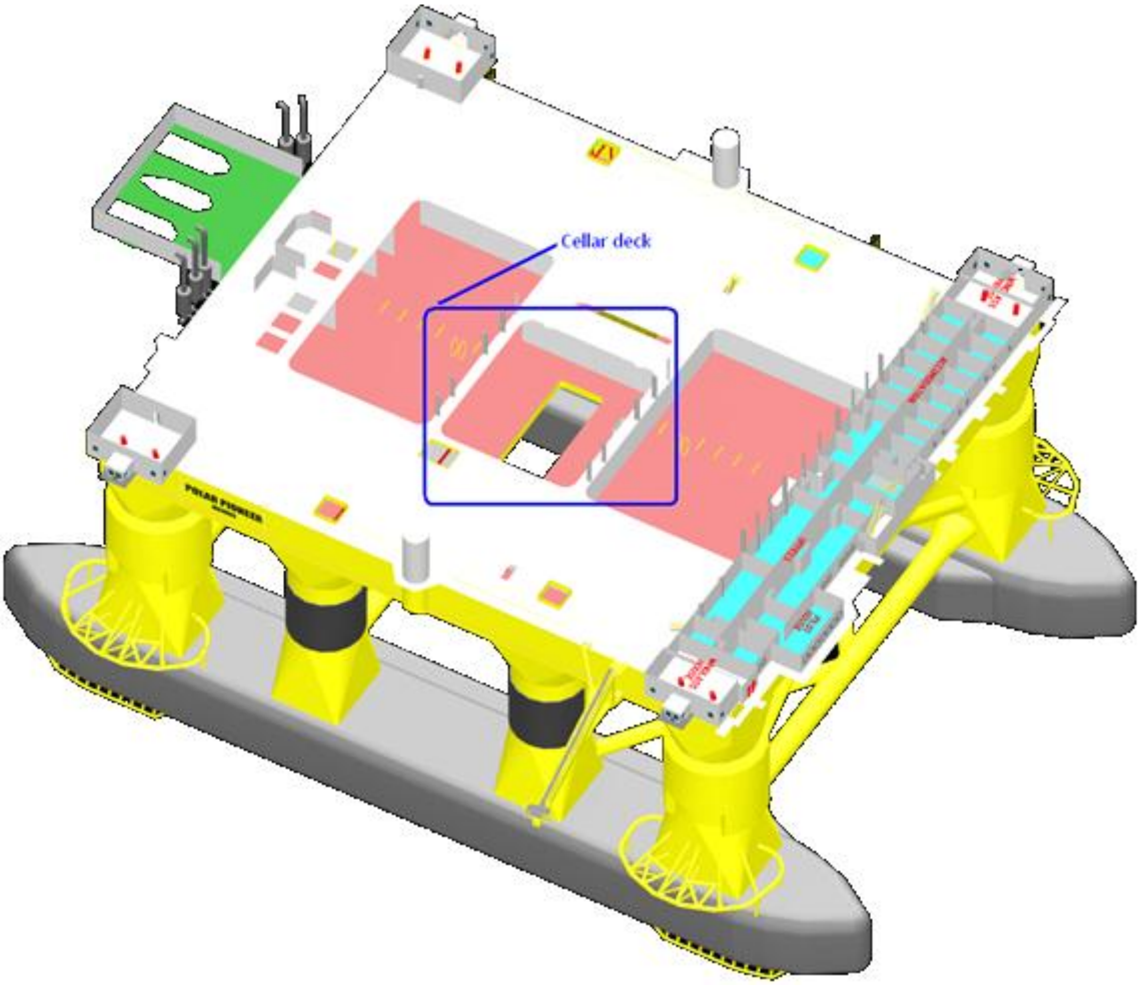



Figure 34: The "Polar Pioneer" seen from STBD. FWD. Main deck in white, machinery deck in pink.(Transocean, 2011)

This area will be the hub for a number of different systems closely supporting the drilling, subsea and/or production part of the overall operation. The area is therefore often highly customized on each rig to fully accommodate the rigs owner/operator specific needs. The biggest movable component in this area is the complete BOP stack being skidded to and from its storage position where maintenance is carried out between wells. The stack can vary in height depending on supplier and setup which often will be well specific. An example of vertical buildup of the BOP is enclosed in Appendix 6.

When approaching drilling contractors (Transocean, 2011) and looking at the vertical BOP skid limitations, the available vertical “play” is in the range between 2-3,5 meter, depending on the amount of equipment that had to be changed. These findings are made by examination of the existing Transocean fleet in Norway, a total of 5 rigs designed in the beginning and mid 80’s. Two of the rigs; Transocean Arctic and Polar Pioneer, have been designed for arctic environment and have performed drilling in parts of the Norwegian Barents Sea. These rigs can therefore, despite their age, be representative for a lower limit with regards to design generation and the particular restrictions that generation impose.

Based on these findings and talks with other drilling contractors, the conclusion can be made that the cellar deck is a highly rig specific area. This is the result of numerous modifications done throughout the rigs life, resulting in highly deviating layouts despite rigs leaving the shipyard as identical basic designs. This introduces a high degree of uncertainty into building our design with the basic assumption of mounting the new components on top of the BOP stack and skid out beneath drill floor.

Conclusively, every increase in height from existing dimensions, would introduce uncertainty regarding if the rig can use our concept without going through possible large refits of piping, cranes, sheaves etc.

Dimensional limitations using cellar deck:

- Width:
    - No practical limitation as long as it is possible to go through the moonpool with the design.
- Height:
    - 2 meters, flange to flange, will be associated with uncertainty

Pros using the cellar deck:

- Will not lead to longer running and retrieval times of the BOP and riser on single activity vessels
- Larger time window can be used on installation, testing etc.

Cons using the cellar deck:

- Large uncertainties with the available vertical height on cellar deck
- Can be a costly implementation round and therefore make the concept ” hard to sell “
- The lower flex joint on top of the BOP is not designed to support large structures in compressive stress and will buckle if not fitted with a support cradle for the SIR.

#### 7.1.5.3 Drill floor

The drill floor is normally where the operational focus is placed. This is the area where most of the hands-on work related to operations is executed, such as:

- Setting up/creating the drilling tools e.g. the bottom hole assembly etc.
- Adding and removing drillstring under normal drilling
- Running and retrieval of
    - Riser and BOP
    - Wire line tools
- Adding the rotational torque needed to make hole

The drill floor is built up around the rotary table which is the start of the “drilling hole” seen from a topside view. The rotary table is a machine capable of rotating it’s center part and can use electric or hydraulic power to accomplish this. The geometry of the rotating part of the rotary table can be of different designs, bushings however will in all cases be used to build the desired hole dimensions for the ongoing operation.

Figure 35: Aker wirth 60 ½" hydraulic driven rotary table shown without bushings

In Figure 35 a rotary table is shown without bushings installed. The bushings are hinged on one side to be able to be installed and removed while a object is present in the hole. In Figure 36 one can see the drilling crew onboard the drilling vessel “CHIKYU” running in hole with the drilling bit. The drilling bit is bigger than the rest of the drill string and the outer bushing and inner bushing is therefore removed. The bushings can be seen in the back/foreground of Figure 36. The inner bushing has a tapered surface. This surface is the female part of the slips, which hold the vertical load of the drill pipe while drill pipe is being added or removed.

Figure 36: Drilling crew onboard the drilling vessel “CHIKYU”

To Install/remove the bushings, lifting yokes combined with chain and hooks are used in premade lifting slots embedded on the bushings. This is shown in Figure 37.

With the rotary table being the foundation for a large part of the operations conducted on the drill floor, standardization soon come into the picture, thus giving the different equipment suppliers a standardized set of limitations on diameters of tools/equipment that can go through the rotary table.

Figure 37: Manual handling of rotary bushings

Rotary tables are delivered in several standardized versions ranging from a open hole diameter from 27½" to 75½" with the industry "standard" on the oldest relevant rigs being 49½". On newer vessels, equipped for deeper waters, larger rotary tables like 60 ½" and 75½" are standard. Choosing to use the 49½" as design criteria might become a engineering challenge, but will guarantee a large user market. If more detailed engineering proves this diameter to be too small, it might be increased to 60 ½" or 75½" on a later stage, depending on the conclusion of a subsequent analysis.

Looking at vertical limitations, the drill floor vertical capacity is high, as the drilling rig normally uses lengths up to 30 meters long drill pipe. Normal riser running deals with the previously mentioned 50 feet and up (15,24 meters) riser length. Using this as a design limitation will guarantee handling capabilities onboard the vessels.

To get an overview, using the rotary table with all its split bushings removed, will give us a standardized foundation to build our design on thus establishing our diameter design criteria to maximum 49½".
Conclusively, less uncertainty is associated using the drill floor to sculpt our design limitations.
Dimensional limitations using Drill floor:

- Width:
  - 49 ½" diameter
- Height:
  - Limited due to "guaranteed" handling to 50 feet.

Pros using Drill floor:

- Good handling capabilities
- Standard dimensional limitations with low uncertainty connected

Cons using Drill floor:

- 49½" width limitations.
- Will lead to a longer time associated with running and retrieval of BOP/riser on single activity drilling vessels

### 7.1.6 Concluding

The previous sections have looked into the limitations as a result of installing and running our concept using the cellar deck and the drill floor. Figure 38 shows how the two approaches give room for different limitations.

Looking at the amount of uncertainty associated with introducing an increased BOP stack height on cellar deck, we soon favor the more standardized limitation we will have to incorporate by going through the rotary table.

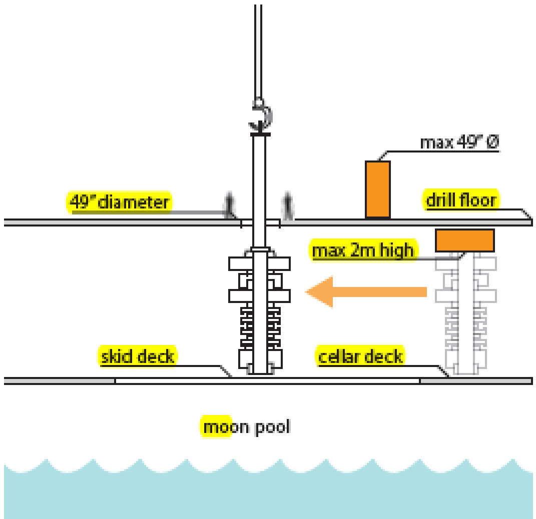



Figure 38: The limitations that the design must incorporate using the cellar deck or drill floor

### 7.1.7 Operational time

Today's procedure related to preparing for a possible disconnect might take up large portions of time that could have been spent in a more productive way. First, the drilling bit must be retracted from the open hole section, to a casing protected section of the well. Not taking the time associated with tripping out of an open hole section into consideration, this thesis goal is to facilitate a mechanical operational time of 5 minutes. This is the time it will take to locate, fixate, de-torque, free and land the tool joint in question. Additional time must be granted to displace riser and prepare for LMRP disconnect.

Concerning the reconnection time of a hung-off drill pipe, a larger time window must be expected. This is due to uncertainties concerning centering, using annular preventer, thread engagement etc. It is believed that this can be achieved well within one hour of LMRP reconnection and this is therefore stated as the design criteria.

### 7.1.8 Operational compatibility

A feasible design will have to be compatible with a certain range of drill pipe sizes. When discussing which drill pipe size to adapt our design to with Professor Sangesland, information was received that the drill pipe sizes most common to use in most drilling operations is 5 ½" and 6 5/8". This is also the sizes that require the larges operational forces. Therefore, adapting our design to these drill pipe dimensions gives a favorable approach to tool joint dimensions. If required, it would be possible to widen the operational limit to include smaller drill pipe sizes on a later stage.

Odfjell well service rents out drill pipe to drilling contractors in Norway. They provided us with some discarded tool joints to study to help us be creative when in the idea phase of making the concept. The 6 5/8" pipe dimensions are attached in Appendix 9 .Please note that these TJ's are made 2" longer than the standard.

### 7.1.9 Concept requirements conclusion

The requirements can be divided into the following segments:

- Safety
- Handling
- Technical
- Operational

**Safety:**

- Internal pressure capacity
  The component will have to be designed with a pressure rating equal or higher than the components in the system it is a part of.
- Consequence to existing safety systems
  A solution that will reduce the existing safety systems reliability cannot be introduced. Therefore the component must be able to withstand equal or greater global loads then the system otherwise would experience. Effects of the changes made must also not introduce an unfavorable gain in forces acting for example the wellhead. Power and control system requirements needed to drive the additional equipment cannot degrade existing safety systems power and control reliability.

- Rules and regulations/Standards
  All applicable regulations will have to be fulfilled.

**Handling:**

The crew onboard must handle the component when stacking it into the subsea system. Physical size and weight is therefore important to ease operations.

- Height
  Height is restricted to 50 feet.
- Width
  49 ½" diameters at max
- Estimated weight (in air)
  General handling capabilities must be as good as possible. The added weight will increase loads on the BOP stack and must therefore be kept as low as reasonable possible.
- Impact due to sea current
  The current forces imposed on the subsea components can be of a significant magnitude. The components should be designed to minimize the current drag forces.

**Technical:**

- Maintainability
  Component reliability will be linked to its design and maintenance. Easy access for rig personnel to carry out inspections and maintenance must be incorporated.
- Wear on components due to drillstring movements
  When drilling the well, there will be times when the rotating drillstring might create wear surfaces in the component. This must be imbedded in the design and not compromise the operability of the component.
- Hydrates build up/how to avoid/consequences
  In normal operations there is a chance for hydrocarbons in the form of hydrates building up in places where this is possible. This might prevent us from operating the components as wished. The design should therefore take this into account and try to prevent such buildup. It should also have the possibility to flush possible volumes where hydrates are present with chemicals in flush ports.
- Buildup of drill cuttings or other mud related components
  Normal drilling cuttings and mud additives might build up in cavities and decrease equipment reliability if not taken into account
- Pressure drop across the subsea pipe breaker
  It is of high importance that the pressure drop across the component is as low as possible to minimize static and dynamic mud pressure differences at drill bit.
- Be able to firmly latch on the tool joint and deliver accurate torque on 5 ½" and 6 5/8" drill pipe (Gabolde and Nguyen, 2006), se Table 10.

| Drill pipe slice [inches] | Max Tool joint outer diameter[mm] | Make up torque[Nm] |
|---|---|---|
| **5 ½** | 177,8 | 45270 |
| **6 5/8** | 215,9 | 88090 |

Table 10: Requirements related to tool joint size and make up torque

- Locating and latching on to a TJ
  Must be able to land/locate and latch on to opposite sides of a TJ. As a result 30 tons in vertical force must be taken up by the engaging cylinders
- Torque
  Be able to break out 6 5/8" DP resulting in a dimensional torque capacity of 105 708 Nm
- Clamping force
  To transfer the torque, a clamp force of 682,7 kN is required
- Vertical load from riser
  A vertical load of 1000 tons should be handled by the conceptual design
- External pressure
  The concept should sustain a max operational water depth of 4000 meters

**Operational**:

- Ability to maintain full riser bore if single or multiple failure is present
  A component that will be narrower than the existing riser/BOP bore cannot be introduced as this will create operational limitations.
- Use of standard components
  The design should try to use existing components to ease production and increase reliability.
- Operating reliability
  Should be as high as reasonable possible and should have a maintenance interval that is at a minimum equal to the BOP maintenance schedule.
- Operational time
  5 minutes operational time in the disconnection phase
  1 hour in the reconnection phase
- Operational complexity
  Operational complexity should be kept as low as possible. One person should be able to run the process. Automatization with manual intervention should be studied to increase reliability and reduce time.
- Stuck tools
  The design must minimize the possibility for bottom hole assembly/DP/wire line tool etc. getting stuck while running in and out of the hole.

## 7.2 The different methods

In the process of designing tools managing the challenges described so far in the document, an open ended approach was used. This means that no idea was considered impossible and no costs or practical limitations were considered. This is done to enhance the creative process and aim at discovering spin-off ideas that emerge from the sum of proposals laid out on the designers work bench. The following ideas where considered as alternatives to today's procedures.

### 7.2.1 Pyrotechnics

The use of explosives in the drilling industry to shoot of drill pipe is widely known. This is done when drill pipe has been jammed or is stuck in a section of the well. An explosive charge is then lowered down to the allocated depth and detonated, freeing large parts of the drill pipe. The affected well section is then cemented and can be re-drilled with a new trajectory. Running the explosive charge is mostly done with the use of wire line. A modified version of this method was used by Statoil on one of their fixed platforms (Eck-Olsen, 2007). The procedure is based on pre-torqueing the drill string with a pre calculated CCW torque. Then the charge is lowered down and detonated at a location near a suited TJ, see figure Figure 39. The shock created by the detonation will lower the needed torque and open up the TJ connection. The idea is to use the same setup and performed the following procedure.

1. POOH untill drillbitt is inside last casing
2. Run in wire line tool with explosives through the top drive (DDM) inside DP
3. Activate AHC
4. Land tool joint in pipe ram, maintaining some tension in the DP
5. Apply CCW torque with DDM
6. Detonating the charge alongside desired tool joint
7. Spin out DP and pull inside riser
8. Close LMRP annular preventer and prepare to disconnect the LMRP from BOP

The method is generically visualized in Figure 40.

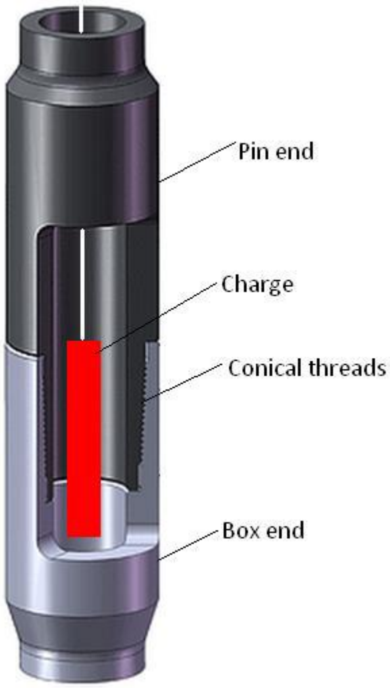



Figure 39: Drillpipe shown with explosive charge (VAM)

The method is simple but as explained by Eck-Olsen, there are large uncertainties when it comes to the amount of explosives. Detonating a large amount of explosives within the BOP would also introduce some risk. The main focus would be the sealing capabilities of the pipe ram in use and the seals in the wellhead and LMRP connector, after detonation of the explosive charge. In addition to this the torsional energy built up in the CCW pre-torqued drillstring, will upon release, create the possibility for another TJ connection to spin out due to inertia. This was experienced by Statoil on their field test. This would mean that we might lose the drillstring down on the exposed pipe ram and its seals. The entire BOP would then have to be pulled out for inspection and repair.

If the drill pipe is not landed in the slips in the rotary table as described in 7.1.5.3, the torque shock would travel all the way up in the DDM, exposing the delicate components for peak loads and probably increasing maintenance cost.

All of the above gives reason to believe that this method would be time consuming, not reliable and therefore not be feasible to replace today's methods.

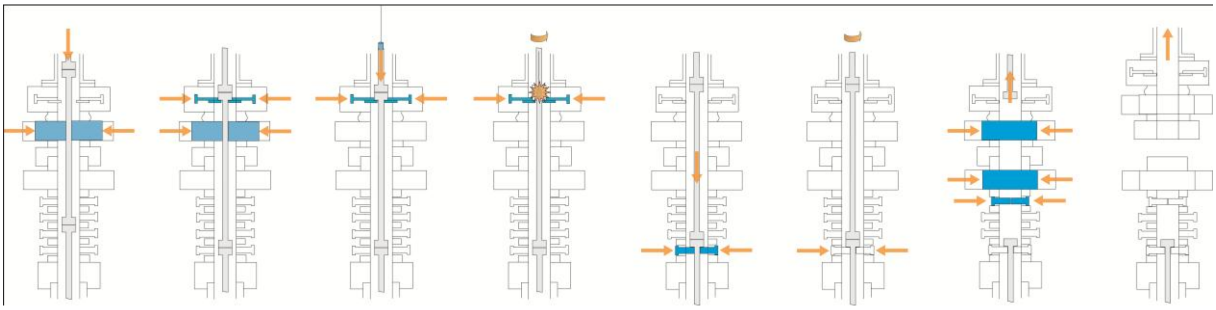


Figure 40: Idea behind using an explosive charge while disconnecting

### 7.2.2 Vibration

The open ended approach included examining the possibility of introducing a mechanism that created vibrations over a tool joint. The idea being that a vibrating tool joint in its resonance zone, with a low CCW torque going across it, will unscrew and lower the inherent connection torque. This was assessed as a possible way of avoiding the large forces as a result of the full break out torques required to carry out a controlled opening of a tool joint connection. The method is generically visualized in Figure 41. After discussing the approach for some time, the conclution that vibrations would have possible unforeseen consequences for bolted connections, seal surfaces and various advanced assemblies already in place subsea, was taken. This method was therefore also abandoned after some initial rounds of developing.

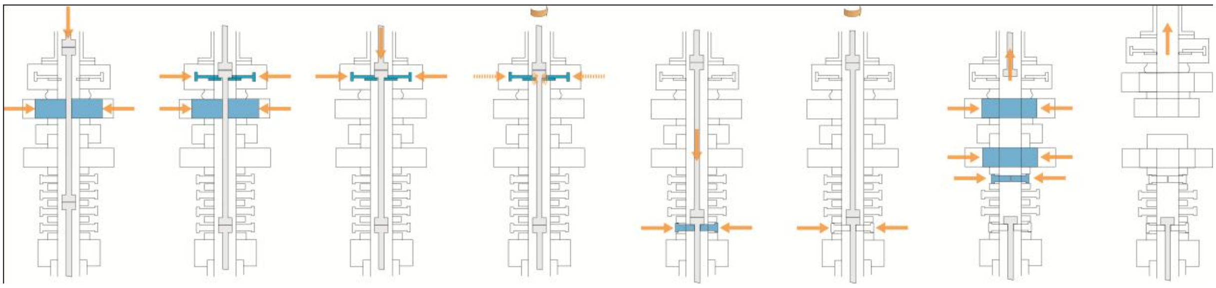


Figure 41: Idea behind using vibration to lower TJ break out torque while disconnecting

### 7.2.3 Modified BOP

In order to keep the system complexity on a minimum and also to minimize costs related to necessary modifications, we started to examine the possibility of using existing BOP equipment to facilitate de-torque of the TJ connection.

The idea is to locate and land DP as done today, mechanically in the BOP pipe ram. Then we introduce a set of wide pipe rams spaced vertically one drill pipe length above the landed TJ. This set of pipe rams is designed to latch on to the TJ tong space both on the pin and the box end, thereby compensating for the variation in TJ lengths. A CCW torque is then applied by the upper pistons, de-torqueing the TJ held in place by the engaged BOP pipe ram to a pre-set value. The upper wide pipe rams are then retracted, and the TJ in the BOP pipe ram can be spinned out using the DDM. The drill pipe is then two separate parts and the upper one can be retracted into the riser. The series of actions is shown in Figure 42

One of the challenges with this method is the use of the BOP as a functional mechanism outside its main work area, namely as a barrier. In addition, the pipe ram must handle large torques and must be re-designed with regards to its gripping surfaces. The proposal will also include that large torques will travel across the BOP stack and the DP body. Large torques over these elements is not the most favorable approach.

This method has been looked at before (Sønstabø, 2007) and in the authors project thesis autumn 2010. Although the ideas vary in details, the use of the BOP and the introduction of new components in the BOP create some initial doubt both by authorities in the form of NPD and by the industry.

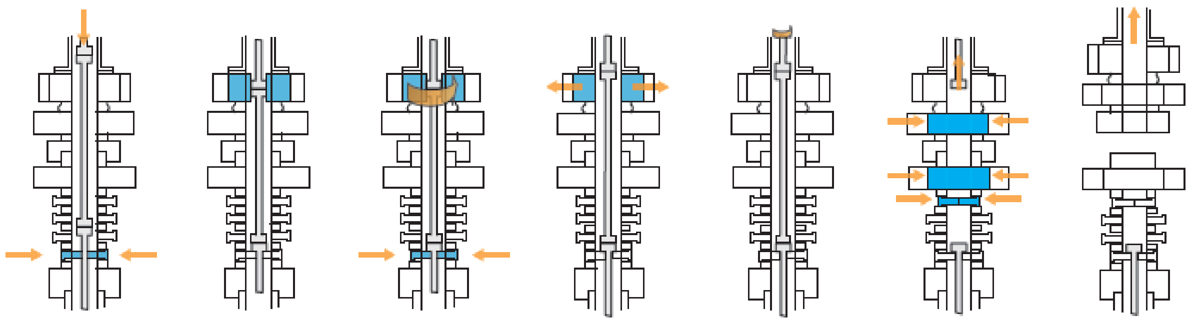


Figure 42: Modified BOP generic sequence. The TJ in the BOP pipe ram is the one that is de-torqued

### 7.2.4 Iron roughneck design

The topside use of iron roughnecks have been an industry standard for many years. The idea in the following sections is to use some of the design features found on topside roughnecks and adapt them for the operational requirements stated.

#### 7.2.4.1 Circular torque Wrench

One concept in particular was developed in the author's project thesis was using the 18 ¾" BOP bore as a design basis and trying to use a circular design, the use of a circular torque tool became a possibility. This concept is called the Circular Torque Wrench (CTW) The idea is to have two sets of dice jaws placed with a suitable vertical space out. Each of the jaw sets consists of 4 pistons. The lower pistons are fixed and latch on to the box end of the tool joint and hold it in place. The upper set of pistons is located in the torque tool. These pistons are rotated with the torque tool after latching on to the pin end of the DP. This gives the possibility of applying continuous high torque in both CW and CCW direction, without having to reorient the grip. This leads to the ability of final make up of DP subsea thus minimizing tripping. When the torque wrench is not in use, the pistons are retracted and full riser bore is achieved. A fail safe design with regards to full riser bore in all eventualities can be built-in by using springs and a failsafe directional control valve. The design is clean and slick seen from the riser bore and there is a minimal posibility of stuck DP or tools due to the machine. The pressure drop due to drill fluids flowing over the CTW is also greatly reduced compared to other concepts studied in the same project. Build-up of mud additives or hydrate is kept to a minum by sealing the riser from the internal CTW components. The complete CTW assembly is represented in a cross section view in Figure 43.

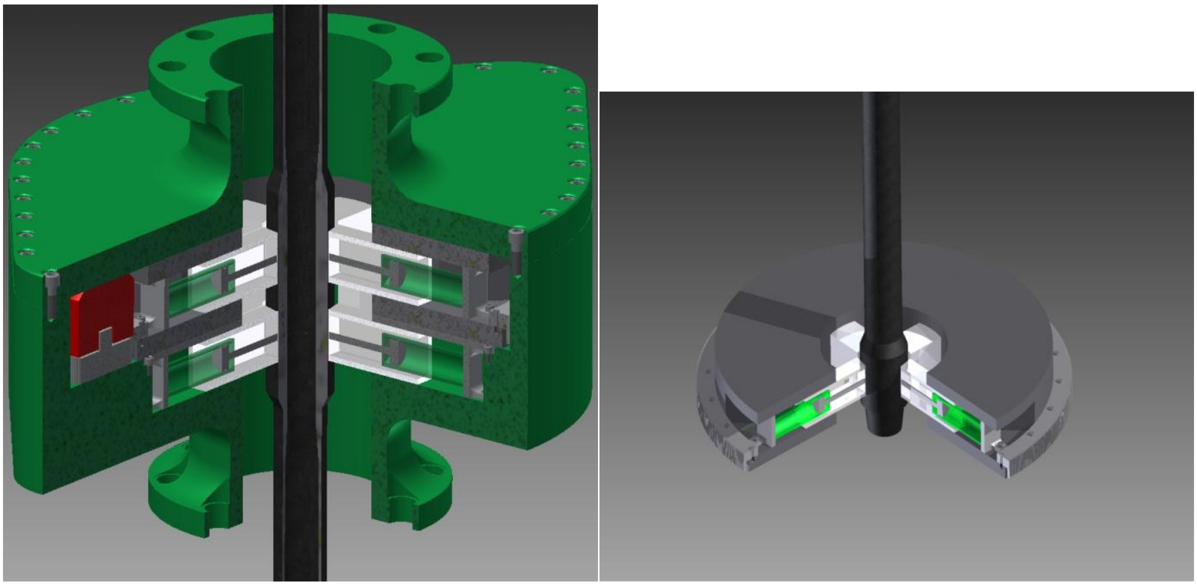


Figure 43: Cut away view of concept utilizing circular torque tool driven by hydraulic motors shown in red. Torque tool shown in right figure

The torque wrench will be placed above the lower flex joint prior to skidding the BOP out in the moonpool area, due to difficulties to obtain a design under the 49 ½" diameter limitations stated in the design requirements. This leads to a dependency on available vertical free-play, adding a negative characteristic to the design. The CTW is shown installed on the BOP stack on Figure 44.

The CTW has a standard riser flange which is connected to a riser when the BOP with CTW is placed below rotary. Tension is then applied and the complete subsea stack is run according to today's procedures.. The conceptual dimensions are summarized by:

| CTW Dimensions | |
|---|---|
| **Height between flanges** | 1195 [mm] |
| **Width** | 2114 [mm] |
| **Depth** | 1510 [mm] |

Table 11: Conceptual dimensions

This concept has some drawbacks. The torque tool has a 360° rotation. After additional work was performed in the understanding of the de-torque sequence, the assumption that most of the torque is removed within the first 30° of rotation, was a feasible design requirement. The full rotation therefore complicates the design without adding any large operational advantages. The riser forces must be carried over the bolted connection on the outer part of the upper cover. The forces in the bolted connection would be large. Applying the dimensioning riser loads mentioned in the design requirements, some deflection of the seal surface of the cover be could expect. The design approach using the wide cover is not the ideal way of transferring the loads. Work was therefore continued on developing a more suited design

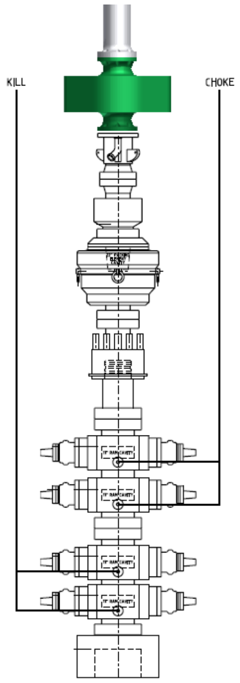



Figure 44: BOP stack with CTW installed

#### 7.2.4.2 Subsea Iron Roughneck, sector based

The work on the concepts gave important knowledge into what qualities we wanted from the end design. Several good ideas had created the understanding that the components needed to transfer the loads in a manner as close to the original marine drilling riser as possible. In addition, we wanted to restrict our operational angle of torque, to allow for better load handling and to simplify the design. The basic idea of the circular design from the previous concept was a good attack angle and it was decided to continue along this path. Out of these conceptual limitations, the idea of using a modified riser pup joint was developed. The basic idea of using a normal riser pup joint modified with two vertical flanges for mounting of machinery modules is shown in Figure 45.

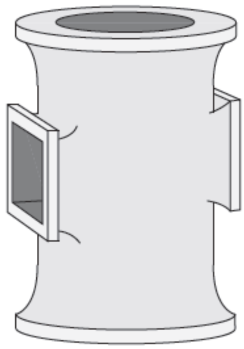


Figure 45: Riser pup joint with vertical flanges

This design gave the following advantages:

- We could rely on the load bearing parts of the design to be narrower that the 49 ½ "stated in the requirements, making it possible to run the concept trough rotary.
- We could simplify the load bearing part of our design to a level similar as a normal riser pup joint. Optimization on the dimensions of the riser pup joint can be done to give it the required bending stiffness and length and at the same time use the same modules to house the torque machinery.
- We could modularize our design into machinery modules. This will simplify maintenance on- and offshore and create easy handling. It also created the opportunity to utilize several locations on the rig for maintenance work etc.

The end result of the pup joint design is shown in Figure 46. This riser pup join has been tested with regards to load cases and has been proven conceptually able to transfer the loads stipulated in the design requirements. For details on load bearing capacities, reference is made to Trond Schou Moum's master thesis (Moum, 2011).

Figure 46: SIR riser pup joint

With the riser pup joint design established, the focus can be directed towards developing functional mechanical modules capable of locating the TJ, delivering the required clamp force and torque. Several module designs were looked upon as capable of fulfilling our needs. Reference to Trond Schou Moum's master thesis is given for details on the different layouts and mechanical solutions (Moum, 2011). The basis for all the internal designs was the concept of using only two upper cylinders and 2 lower cylinders. The internal design chosen will be described in detail.

The two lower cylinders consist of a tool joint locator and a set of dices designed to be compatible with 5 ½" and 6 5/8" DP. The upper cylinder is also fitted with a similar set of dices. One of the lower cylinders is shown in Figure 47. The tool joint locator shown in the lower part of the cylinder can be moved independently from the rest of the cylinder.

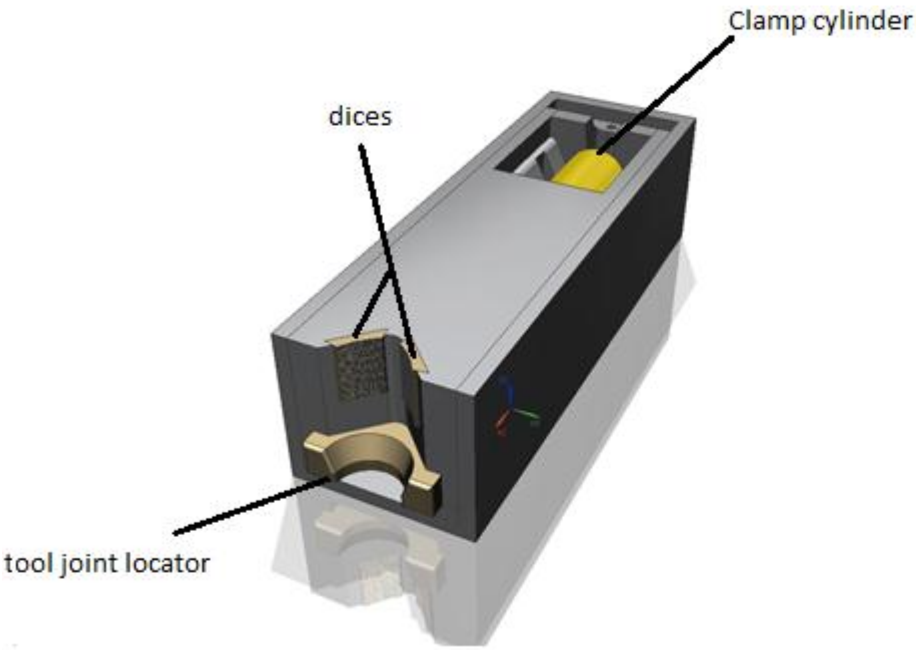



Figure 47: Lower clamp cylinder with tool joint locator

This cylinder set is designed to have the ability to deliver the required makeup and break out torque. This is done with the use of a rotating jaw in combination with a slide and a dedicated torque cylinder shown in Figure 48. The rotating jaw is driven by a shaft installed vertically in the jaw slide, connected to the torque cylinder. The vertical shaft is supported by support slides in the bottom of the housing and in the belonging upper cover. This support of the shaft takes the side acting forces as a result of the jaw slide path and torque in the TJ. This removes side forces from the hydraulic torque cylinder and protects the cylinders front bushing and seals from accelerated wear. The bottom of the housing with the support slide, torque cylinder and vertical shaft is shown in Figure 49. In this figure the clamp cylinder is retracted, in figure Figure 50, this cylinder is shown in its expanded position.

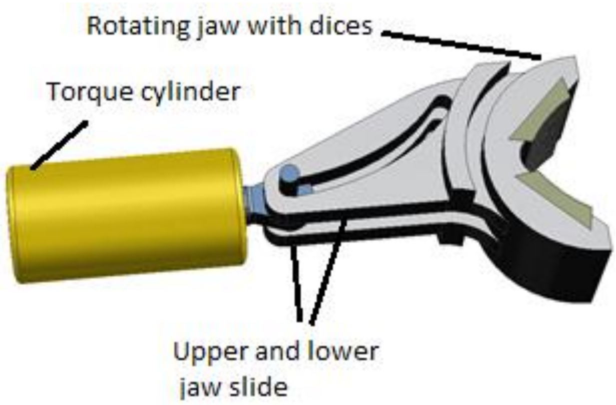



Figure 48 Rotating jaw with upper and lower jaw slide

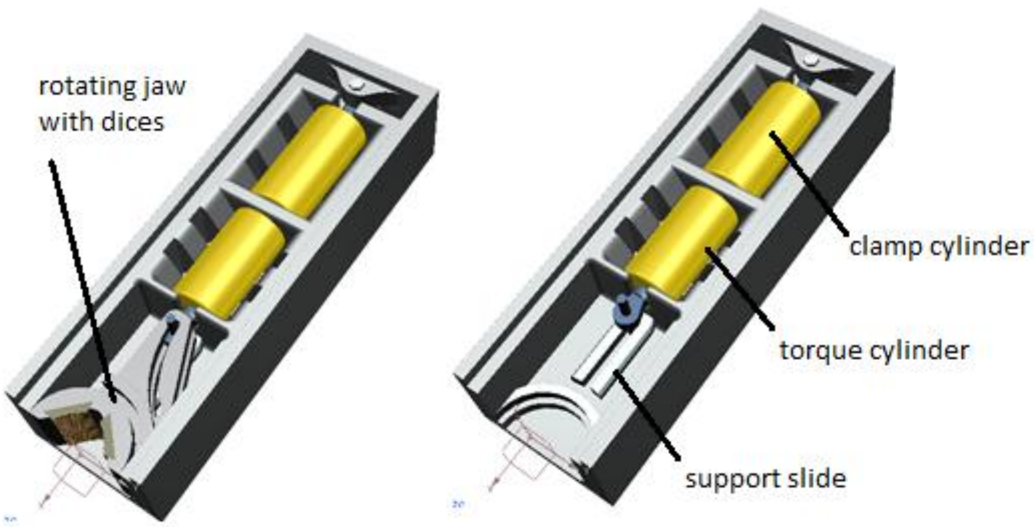
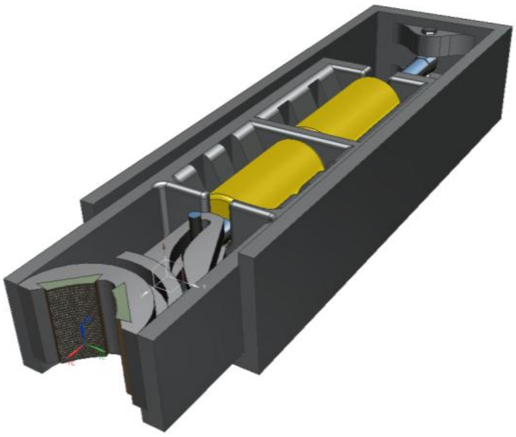



Figure 49 : Upper clamp cylinder shown without its cover installed and with/without rotating jaw

This rotating jaw design has high torque capacities in both CW and CCW direction. The design allows for optimization of the slide path when practical tests show the needed torque-turn graphs. The rotation of the dice jaw is shown in Figure 50. The design chosen fulfills the 15° requirement stated in the design requirements.



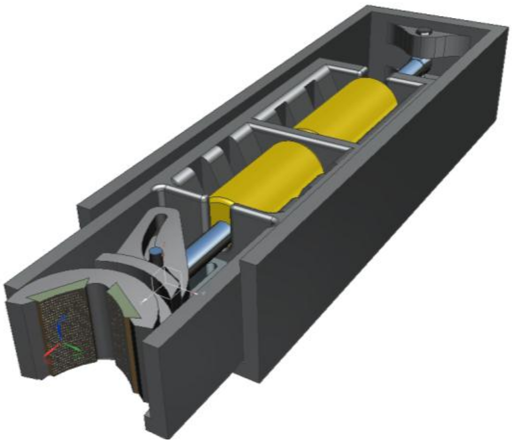


Figure 50: Upper clamp cylinder shown without cover installed. Torque mechanism in retracted and expanded position giving a 15 ° operational rotation

The upper and lower clamp cylinder is installed in the machinery module housing vertically above one another with a spacing designed to comply with the available tong spaces. This is shown in Figure 51.

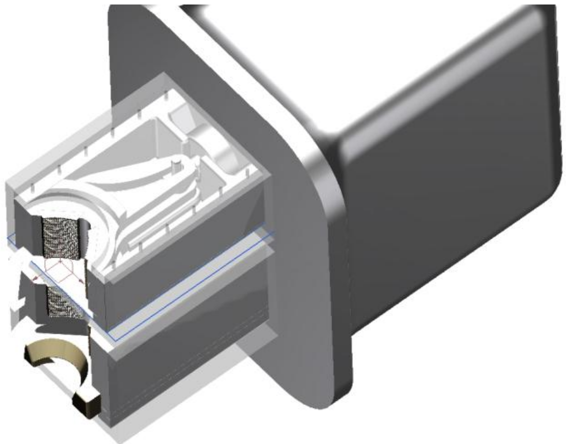


Figure 51: Machinery module with transparent cover on upper clamp cylinder

The complete machinery modules with its internal components are bolted on to the vertical flanges on the SIR riser pup joint. This is shown in figure Figure 52. This unit is placed above the BOP as illustrated in Figure 53.

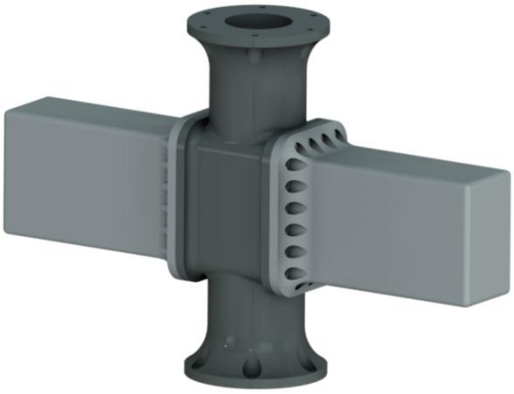


Figure 52: The SIR with all components installed

The operational sequence of the SIR is thoroughly presented in chapter 8 and the SIR de-torque sequence is visualized in Appendix 18. The SIR concept has the physical conceptual dimensions illustrated in Table 12. For more details on dimensions, reference is made to Appendix 15 to Appendix 17.

| SIR Dimensions | |
|---|---|
| **Height between flanges** | 2500 [mm] |
| **Width including modules** | 3875 [mm] |
| **Width excluding modules** | 990 [mm] |
| **Depth** | 990 [mm] |
| **Max weight in air** | 16 [tons] |

Table 12: SIR conceptual dimensions and weight

The riser pup joint is transported to and from vessel location with protector plates installed on the machine module flanges. The plates should be designed such that all sealing surfaces are protected and the fasteners used are protected from damages occurring while handling the equipment.

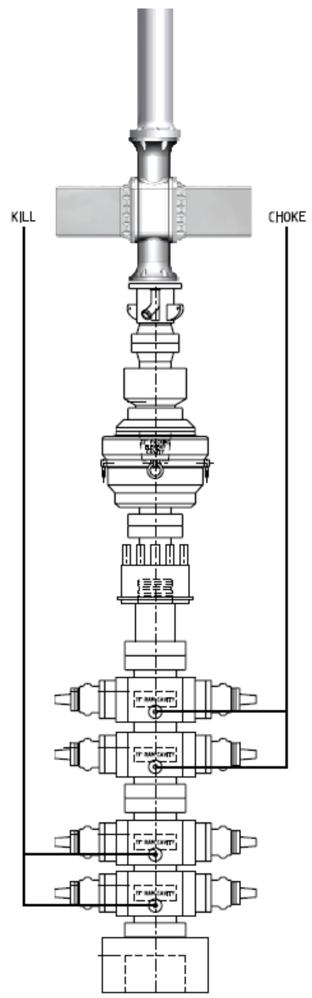



Figure 53: The SIR installed on the BOP

## 7.3 Rating concepts

Before detailed engineering is started, the best concept will have to be chosen. There are several methods used today to rate conceptual designs. This particular step of a design process is often associated with loose assumptions and "gut feeling" as the most common rating method performed is a quantitative system rating.

The system is evaluated by a set of criteria's and given a value based on its assumed or historical performance on a scale from for example 1-10 where 10 is the best performance. The criteria's are given a relative importance, often called weighting factor. The overall summation of the performance value multiplied with the criteria weighting factor, will give the system/concept overall performance (Thompson, 1999):

$$P = u_1 \times k_1 + u_2 \times k_2 + u_3 \times k_3 + \cdots u_n \times k_n \tag{1}$$

Where : P = Overall performance
$u_n$ = Criteria performance value
$k_n$ = Criteria relative importance

The design proposal with the highest number value of P will be the preferred conceptual design based on the weighting and the performance values given by the designers.

One problem by using the above described method is that numerous criteria's are used. This migh create a tendency to produce an overall performance value of similar level for all of the designs because the good and bad aspects of each design tend to average out to a common level.
As mentioned above, this method is often given a gut feeling approach as many of the performance values must be estimated using engineering reasoning. This method is therefore also prone to some subjective bias(Thompson, 1999).

It is therefore important to give reasonable arguments when assessing the performance values. The numbers must under no circumstances be "plucked from the air".

One method mentioned in the relevant literature (Thompson, 1999) is to choose a "neutral" design and design criteria's, then rating the other conceptual designs with this datum concept as a base line. The subsequent rating is performed only with the use of summation and subtraction signs, the method is shown in Figure 54. This gives a more qualitative approach with fewer pitfalls in a conceptual phase where few or none details are accessible to the designer.

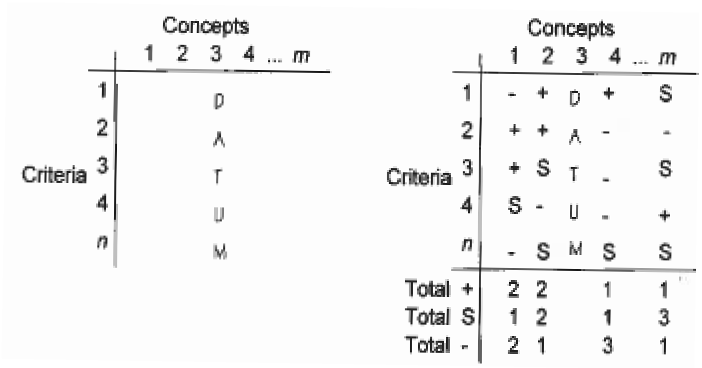



Figure 54: Quantitative concept evaluations method example(Thompson, 1999)

There is also a method for evaluating if too many criteria's have been used and that the good sides wheigh up for the bad sides of the specific design. This method is called Device performance index (DPI) and is a quantitative method. It is more or less built up in the same manner as the quantitative addition method, but aims at reducing the shadow effects and is thus an improved method. The same rules apply to this method when assessing performance values, the number of criteria's and the criteria relative importance. The formula of weighted DPI can be expressed as (Thompson, 1999):

$$DPI_k = \frac{\Sigma k_i}{\Sigma \frac{k_i}{u_i}} \tag{2}$$

Where: $DPI_k$ = Overall concept performance using Device performance index
$u_i$ = Criteria performance value
$k_i$ = Criteria relative importance

Our approach to this challenge is to use a scale from 1-5 where 3 is a neutral attribute and 5 is the best score. We will try to minimize the number of criteria's taken into the account and to use weighting factors only when strictly necessary. We will base our rating on the basic addition method but will perform a sensitivity analysis with a weighted DPI method to see if the outcome of our analysis will be different. This will combine what we find attractive with the qualitative "plus-minus "method with the more agile quantitative addition method. At the same time this will give a insight into the strength of our results when performing a DPI rating.
The concepts chosen to be rated is the modified BOP covered in Section 7.2.3, the CTW covered in 7.2.4.1, and the SIR covered in Section 7.2.4.2

### 7.3.1 Rating results

The rating results using the summation method is shown in Table 13.

| | | Concept | | |
|---|---|---|---|---|
| weight factor | | CTW | BOP | SIR |
| **Safety:** | | | | |
| 5 | interference on existing safety systems | 5 | 1 | 5 |
| 4 | operational reliability | 3 | 3 | 4 |
| | **Safety sum** | **37** | **17** | **41** |
| **Handling:** | | | | |
| **3** | additional rigging needed in running and retrieval | 1 | 3 | 2 |
| 4 | height | 1 | 4 | 3 |
| 2 | width | 2 | 3 | 5 |
| 2 | weight (est. in air) | 2 | 4 | 3 |
| 1 | hydrodynamical impact | 3 | 4 | 2 |
| | **Handling sum** | **18** | **43** | **36** |
| **Technical:** | | | | |
| 2 | manufacturing complexity | 2 | 3 | 5 |
| 3 | load handling | 2 | 4 | 4 |
| 1 | drill cuttings build-up | 4 | 4 | 4 |
| 1 | pressure drop over the components | 3 | 4 | 4 |
| 3 | maintainability | 3 | 2 | 5 |
| 1 | required redesign of existing systems | 5 | 1 | 5 |
| | **Technical sum** | **31** | **33** | **50** |
| **Operational:** | | | | |
| 3 | localizing tool joint | 3 | 5 | 3 |
| 1 | centering | 3 | 5 | 3 |
| 2 | grip on lower part of tool joint (box) | 5 | 2 | 5 |
| 2 | grip on upper part of tool joint (pin) | 5 | 5 | 5 |
| 2 | torque | 5 | 3 | 5 |
| 1 | speed | 5 | 2 | 5 |
| 3 | operational repetability | 5 | 2 | 5 |
| 2 | monitoring accuracy | 4 | 1 | 4 |
| 3 | operational complexity | 4 | 1 | 5 |
| | **Operational sum** | **82** | **53** | **85** |
| | **TOTAL WEIGHTED SCORE** | **168** | **146** | **212** |

Table 13: Rating of the concepts using the summation method

Using the DPI method we get the result shown in Table 14

| | | Concept | | |
|---|---|---|---|---|
| Weight factor | | CWT | BOP | SIR |
| **Safety:** | | | | |
| 5 | interference on existing safety systems | 5 | 1 | 5 |
| 4 | operational reliability | 3 | 3 | 4 |
| | **Safety sum** | **3,9** | **1,4** | **4,5** |
| **Handling:** | | | | |
| **3** | additional rigging needed in running and retrieval | 1 | 3 | 2 |
| 4 | height | 1 | 4 | 3 |
| 2 | width | 2 | 3 | 5 |
| 2 | weight (est. in air) | 2 | 4 | 3 |
| 1 | hydrodynamical impact | 3 | 4 | 2 |
| | **Handling sum** | **1,3** | **3,5** | **2,7** |
| **Technical:** | | | | |
| 2 | manufacturing complexity | 2 | 3 | 5 |
| 3 | load handling | 2 | 4 | 4 |
| 1 | drill cuttings build-up | 4 | 4 | 4 |
| 1 | pressure drop over the components | 3 | 4 | 4 |
| 3 | maintainability | 3 | 2 | 5 |
| 1 | required redesign of existing systems | 5 | 1 | 5 |
| | **Technical sum** | **2,6** | **2,5** | **4,5** |
| **Operational:** | | | | |
| 3 | localizing tool joint | 3 | 5 | 3 |
| 1 | centering | 3 | 5 | 3 |
| 2 | grip on lower part of tool joint (box) | 5 | 2 | 5 |
| 2 | grip on upper part of tool joint (pin) | 5 | 5 | 5 |
| 2 | torque | 5 | 3 | 5 |
| 1 | speed | 5 | 2 | 5 |
| 3 | operational repetability | 5 | 2 | 5 |
| 2 | monitoring accuracy | 4 | 1 | 4 |
| 3 | operational complexity | 4 | 1 | 5 |
| | **Operational sum** | **2,7** | **1,6** | **2,3** |
| | **TOTAL WEIGHTED SCORE** | **2,5** | **2,1** | **3,8** |

Table 14: Rating of the concepts using the DPI method

Applying the results of both rating methods , reveals that the SIR design is the concept that receives consistent better rating. Based on this and a dialogue between the designers and their advisors, the SIR concept is chosen as a basis for all further design work.

## 7.4 Cost reduction with improved disconnection method

Earlier in this thesis an operational log was presented, showing in detail the time spent on while preparing and waiting on weather on a midwater well. 19 hours and 45 minutes was used from the decision was made to RIH with the EDPHOT, to the actual disconnection.

There are two points that are important to emphasize in this context:

- The weather did not show trends of exceeding the operational limits before approximately 45 minutes before disconnection of the LMRP.
- The weather could easily have calmed down at that time, making the use of the EDPHOT and the subsequent WOW, unnecessary.

In both cases, a more efficient way of disconnecting would be preferred.

We assume that the displacing of the marine drilling riser will take 1,3 hours including all activities (lining up, pumping etc.) and that the DP de-torque and hang off sequence is completed within 5 minutes.

Based on the reduction in time used by the elimination of the EDPHOT, the decision to displace and prepare for hang off would be done on the basis of new criteria's with regards to environmental conditions. We can therefore say that the rig would be operative and constructing well until Saturday morning at 0330, 17 hours and 30 minutes later than with the use of the EDPHOT.

This gives a reduction from 19 hours and 45 minutes to 2 hours and 15 minutes. Assuming the same standby rate of 350 000 $/day, this would give the operator a 255210 $ cost saving due to reduced WOW. We are now only conceding one well and one possible disconnection. If the new and wider operational limitations had not been exceeded, the cost saving would be higher as it would not be necessary to interfere with planed well construction tasks at all.

The reconnection savings are not large on the water depths in this operational example, as it only involve less than 300 meters of tripping each direction, but the time used on tripping is, as stated before, is proportional with water depth.

The fact that the new and wider operational limits will be in place due to shorter operational times, will affect the operations in arctic areas in a positive way. In Section 6.2 a two cases where assumed disconnection probabilities and the subsequent operational cost while operating in arctic environments was presented.  . It is now possible to re-assess the assumptions in light of the new info on time needed to disconnect and give new estimates of costs related to disconnections using the SIR concept.

The yearly cost for each rig amounted to 1 083 483$. If we choose to implement the SIR method, planned and unplanned disconnections can be treated in the same manner. The operational limitations will be wider and the number of hazardous situations resulting in an actual disconnection preparation will be lower. The probability of planned disconnections will therefore be reduced. On the other hand, the emergency disconnections will have to be treated in the same way as today for safety reasons. Based on this and assuming yearly rate of disconnection for the different methods, we can calculate the new costs related to planned and unplanned disconnections:

| Method | Possibility/well |
|---|---|
| **Use of drill pipe hang off tool:** | 0,25 |
| **Hanging off the drill pipe and shearing** | 0,1 |
| **emergency disconnection** | 0,01 |

Table 15: Possibility disconnection /well with the SIR

Assuming the same 55 day well completion time, gives a yearly production of 6.6 wells. Using this we can estimate the yearly amount of disconnections:

| Method | Possibility*well/year | Number of yearly disconnections |
|---|---|---|
| **Use of drill pipe hang off tool:** | 0,25*6,6 | 1,65 |
| **Hanging off the drill pipe and shearing** | 0,1*6,6 | 0,66 |
| **emergency disconnection** | 0,01*6,6 | 0,066 |

Table 16: Yearly amount of disconnections with the SIR

| Method | Number of yearly disconnections | Yearly disconnection*The sum of disconnect and reconnect time *day rate | Yearly cost related to disconnections in dollars |
|---|---|---|---|
| **Using the SIR** | 1,65+0,66 | 2,31*1,0834*20833 | **56 145** |
| **Emergency disconnection** | 0,066 | 0,066*48*20833 | **65 999** |
| **Yearly total** | **4,026** | | **118 134** |

Table 17: Cost related to planned and unplanned disconnections using SIR

In chapter 6.2 it was estimated that the cost associated with disconnections due to arctic operations amounts to 1 083 483 $/year for one rig operating on midwater wells and 3 748 878 $/year on ultradeepwater wells.

The cost for both these cases are now reduced to 118 134 $/year, a reduction of 965 350 $/year and 3 630 744 $/year corresponding to an 89 % and 97% reduction in costs related to planned and unplanned disconnections. This reduction is not only monetary ,but in some areas where the open water conditions only last for say 60-70 days, the possibility of saving a few days due to less non-productive time, is welcome. Such time savings might be de difference between having large enough time safety margins around the well construction time in the open water period, using a small conventional MODU and going over to a more expensive specialized vessel designed for operations in ice. This difference might make many wells commercially attractive in the harsh environments in the Arctic.

# 8 Operational procedure

The final concept and its limitations and dimensions have now been established. This gives the basis of creating installation, operating and retrieval procedures as the interface between rig and components are now given. This will be the focus of this chapter.

## 8.1 Installation

- The SIR is landed onboard and inspected according to procedure, upon arrival offshore.
- The riser joint is handled with the same tools as other riser pup joints an lifted up to the vessels drill floor
- The BOP is skidded out under rotary while the riser pup joint is lowered down through the rotary table.
- The pup joint lower flange is made up with the riser flange on the lower flex joint.
- The SIR machinery module flange protector plates are removed
- The machine modules can then be rigged from their storage location to their final position on the riser pup joint. This is done with the help of lifting yokes that are designed for a horizontal lift as the component will have a center of gravity that probably will give us a tilt angle if we lift after the flange. The joke should also have some guide pins that locates the right hole pattern on the two mating flanges to save rigging time.
- The control system is connected to obtain hydraulic and control capabilities.
- When the machinery modules are completely installed the final function and pressure tests can be made.
- Conventional riser is ready to be run through rotary and connected to the upper flange on the SIR
- Kill, choke, booster and other auxiliary riser lines are kicked out from the conventional riser and run via flexible hoses over the SIR and lower flex joint, similar to the method used to cross the lower flex joint with today's auxiliary lines.
- The weight of the BOP complete BOP stack, LMRP and SIR is picked up and the skid deck is removed.

The riser string is then run according to company procedures and landed/connected to the wellhead installed subsea. Running procedure complete

The day to day operation will not experience any differences when the SIR is installed and dormant.

## 8.2 De-torque procedures

As described earlier in Chapter 6 there are several triggering factors that might arise and give the drillers/company man's/OIM's attention and give reason to prepare for an upcoming disconnect. When the decision to disconnect is made topside, the procedure performed by the driller will be:

1. POOH to drillbitt is inside last casing
2. Activate AHC
3. Set pressure regulator on tool joint locator in SIR to a low value to allow for vertical motion of drill pipe(500psi),
4. Tool joint locator is moved partly out in the annulus
5. Space out tool joint to be ca. 2 m above lower pipe ram in SIR
6. Center the DP using the upper annular preventer
7. Partly engage the TJ so that movement is registered on both the tool joint locators
8. Slowly lower the drill pipe and set of 5 tons on tool joint locator
9. Engage the tool joint with lower rams with the recommended clamp force on the drill pipe size in use
10. Activate the upper rams to engage the pin end of the hanged of tool joint. Pressure should be regulated to achieve recommended clamp force
11. Open upper annular preventer
12. Activate CCW de-torque sequence.
13. Pick up the 5 tons resting on the lower ram.
14. Retract upper and lower jaws in the SIR
15. Space out de-torqued TJ to be 2 meters above pipe ram in BOP
16. Activate BOP pipe ram with regulated pressure to allow for vertical motion of the DP (500 psi)
17. Land tool joint in BOP pipe ram, following the stipulated BOP vendors landing procedures.
18. Spin out tool joint by applying CCW torque using the DDM
19. Pull DP into riser
20. Close LMRP annular preventer and prepare to disconnect the LMRP from BOP in compliance with today's existing procedures.

Depending on the hazard faced and the assumed situational trends, displacement of the riser can have been done during the entire process or start at a later stage. This is a decision that is up to the driller/toolpusher and company man. The equipment is designed with continuous circulation in mind under the entire process. The process is illustrated in Figure 55 and in Appendix 18.

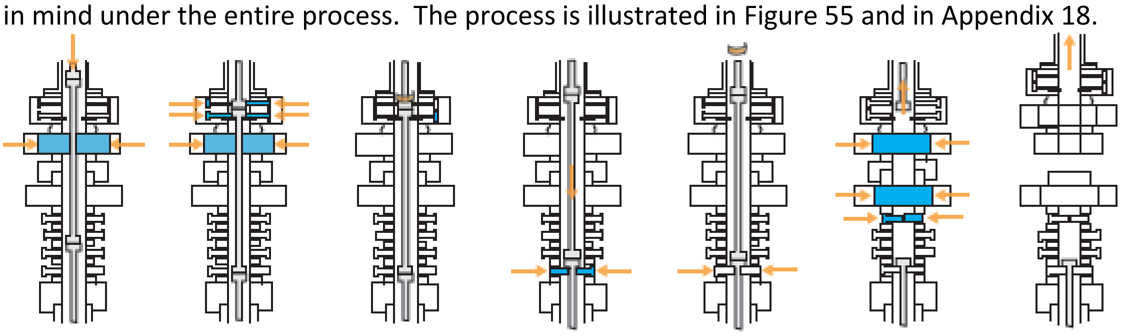


Figure 55: Illustrated SIR operational procedure

## 8.3 Reconnection of LMRP DP procedure

A reconnection can be summarized by the following procedure:

1. When hazard is reduced to acceptable level , preparations are started to landing LMRP
2. Seal ring on hydraulic LMRP connector is replaced by ROV
3. Guide wires are tensioned
4. LMRP landed
5. Read back pressure is obtained
6. When pressure is equalized between riser and well, preventers and required rams can be opened
7. Activate AHC and run DP into the BOP
8. DP is centered with the use of the upper annular preventer
9. The pin is connected to the hug off box end in the BOP pipe ram
10. The threaded connection is made up temporarily with the use of the DDM
11. Complete DP string is lifted up above the SIR
12. Sett pressure regulator on tool joint locator in SIR to a low value to allow for vertical motion of drill pipe(500psi),
13. Tool joint locator is moved partly out in the annulus
14. Space out tool joint to be ca. 2 m above lower pipe ram in SIR
15. Center the DP using the upper annular preventer
16. Partly engage the TJ such that movement is registered on both tool joint locators
17. Slowly lower the drill pipe with the draw work and set of 5 tons on tool joint locator
18. Engage the tool joint with lower rams with the recommended clamp force on the drill pipe size in use
19. Activate the upper rams to engage the pin end of the hanged of tool joint. Pressure should be regulated to achieve recommended clamp force
20. Open upper annular preventer
21. Activate CW torque sequence.
22. Pick up the 5 tons resting on the lower ram.
23. Retract upper and lower jaws in the SIR
24. Land TJ in bidirectional test ram following the supplier procedures
25. Perform pressure test of hydraulic connector seal ring using the bi-directional BOP test ram.
26. When this test is accepted, normal drilling operation can resume.

## 8.4 Retrieval procedures

The riser is retrieved according to existing procedures in place today with the following exception:

1. The BOP comes up through the splash zone
2. BOP lifted above skid deck level
3. Skid deck is positioned below BOP
4. BOP is landed on skid deck
5. Flexible auxiliary riser lines across the flex joint and SIR are removed
6. SIR machinery module is removed
7. SIR control system is removed
8. Lower SIR flange is disconnected from flex joint riser flange
9. Flange protector plates are installed
10. SIR pup joint is picked up and run through rotary
11. SIR pup joint is laid down on deck

SIR machinery modules and pup joint is the subject of routine inspection and maintenance according to operational log findings and as a result of the use it has been subjected to on wells completed.

# 9 Control end monitoring

As the SIR concept is proven operational and mechanical feasible, the need for control and monitoring should be addressed. The complex nature of the operational sequence combined with our need to know and to some extent log our functional actions, demands a thoroughly thought through control philosophy

Before starting to look at control concept, the control system requirements should be established. These requirements will have to give guidance on the following points:

- Number of hydraulic users
  - Pressure rating needed to deliver required force
  - The volume needed to complete one working cycle
- Monitoring needs
  - What do is required to monitor
  - What refresh rates is required on the data
- Energy
  - What hydraulic flow rates will users need
  - What additional subsea equipment will need power and how much do they need

## 9.1 Conceptual requirements

Being in the conceptual design phase means that several of these requirements are not settled as there has been limited detailed engineering performed. We can however establish what we know and work as far as possible with the information at hand. When more detailed information is specified, this can be implemented thus supporting or rejecting the assumptions made in the conceptual phase.

The system consists of four main cylinders that are used to locate and fixate the tool joint that we want to de-torque. In addition, two cylinders to achieve the rotational torque needed to make up/ break out the tool joint to the planned torque. The tool joint locator is also positioned by the use of two cylinders. This give a total minimum of 8 hydraulic user's subsea.

The hydraulic force applied on the drill pipe and tool joint will have to be regulated depending on the drill pipe in question and its recommended brake/make up torque. This will have to be done with the use of hydraulic pressure regulators. The basic design will therefore need pressure regulators for:

- Locating the TJ
- Adjusting clamp force on lower jaws
- Adjusting clamp force on upper jaws
- Regulate applied torque

This gives us a total of 4 pressure regulators.

These regulators deliver pressure to processes that should be synchronized relatively to each other. This must be done by monitoring their position using the linear variable differential transformer technology. This will give the position of each cylinder and will have to be coordinated with the cylinders directional control valve (DCV) for regulation of speed and of position.

The data collected subsea, will need to be visualized and logged topside. The data gathered from subsea load cells, pressure sensors etc. will need to have a lower limit of refreshment. To be able to readout the forces every 0, 5 second is estimated as an absolute lower refresh limit. This refresh rate is chosen to be able to log rapid changes in applied forces due to stick friction and/or impurities creating minor jams in threaded connections etc. Depending on the control system chosen, these refresh rates can increased to almost infinite readouts. But all the control systems that are feasible should be able to refresh every 0, 5 second.

Several control options were considered when preparing this master thesis. They were:

- Use of existing BOP control system
- Use of battery powered subsea hydraulic power unit with acoustic link to the surface vessel
- Use of a separate system based on hydraulic conduit and electrical cable to the surface vessel
- Accumulator based energy stored subsea with possibility for recharging using ROV. Acoustic link to surface vessel

The practice of operating hydraulically mechanisms subsea is widespread within the drilling industry, through the use of the well-known BOP. A conventional BOP control system could in many ways be able to facilitate our control and monitoring needs. An introduction to existing BOP control system will therefore be given.

## 9.2 BOP control systems

All of the mechanical functions of a BOP have in common that a hydraulically driven piston is being forced to move in the desired direction. The control system should therefore in the end;

Direct hydraulic fluid at the correct operating pressure, to the appropriate side of piston associated with the desired function. The fluid on the other side of the piston must at the same time be able to escape to the surroundings or to a reservoir. This must be done while maintaining a high degree of operational reliability and with minimal environmental implications.

Several different control systems have been and are in use. The different approaches can be divided into these main groups:

- Direct hydraulic
- Indirect hydraulic
- Multiplex

### 9.2.1 Direct hydraulic

In the beginning, the use of BOP's was developed for use on land rigs. This meant that both the control system and the BOP itself was and is accessible for hands on verification and maintenance. The distance from the Hydraulic Pressure Unit (HPU) to the BOP is limited by the distance looked upon as safe by the crew setting up the land rig as can be seen in Figure 56. The system is designed as a directly hydraulic operated system which means that there is dedicated hydraulic hoses for each function from the hydraulic control manifold to the functional user. These hoses are big bore hoses to improve the hydraulic flow when operating a function. The associated pressure drop over a length of pipe/hose can be described as (Kjølle, 1995):

$$\Delta p = \rho\lambda \frac{L}{D}\frac{c_m^2}{2} \tag{3}$$

Where: $\Delta p$= pressure drop
$\rho$ = fluid density
$\lambda$ = friction coefficient as a function of the Reynolds number and the pipe wall roughness
$L$ = Length of pipe to be used
$D$ = pipe diameter
$c_m$= the flow velocity

Studying this expression we see that the flow velocity affects the pressure drop by the power of two. Increasing the sectional areal i.e. the diameter, we will deliver the same volumetric flow to the user, but reduce the flow velocity. At the same time the increased diameter is contributing to a lower $\Delta p$ as the function is divided by D. It can therefore be concluded that it will be beneficial from a hydraulic point of view, to operate with large diameter hoses or pipes.

As mentioned in the definition of what a BOP system must fulfill, the need for fluid escape is stated. This is called venting and refers to ventilation of the chamber that is going to be compressed such that the fluid occupying the volume can escape. The vented side of the user in a direct hydraulic system is drained to the main reservoir trough the dedicated hose already connected to that side of the user. The system is therefore classified as a closed hydraulic system with no spills to the surrounding environment. This control approach is still in use on land rigs, jack-up's and platforms as the BOP sits accessible for the crew and where the distance from the hydraulic unit to the end user is small.

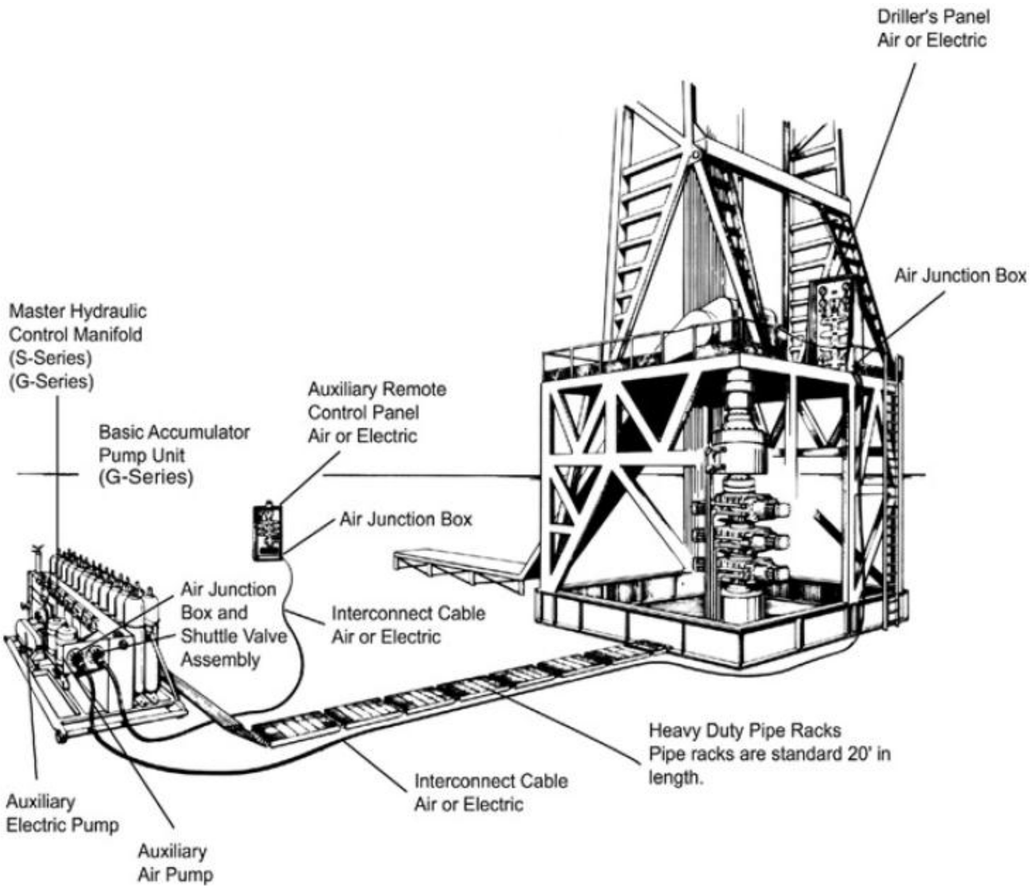



Figure 56: Land rig BOP setup(P.Potter, 2011)

When the industry started operating from floating drilling rigs in the 60’s, the practice of deploying the BOP in the water and operating it while situated on the seafloor was introduced. The same direct hydraulic principles were used.

With time, the operational water depths kept on increasing. The subsequent length of hydraulic hose exposed to operational pressure would therefore increase correspondingly.

When pressurized from the ambient pressure to the working pressure of 1500-3000 psi, flexible hydraulic hose is somewhat expandable, the consequence of this being a time lag from activation of function topside to required pressure buildup and function execution subsea. The change in conduit cross sectional areal can be expressed as(Kjølle, 1995):

$$\Delta A = \frac{\pi D^3 p}{4Et} \tag{4}$$

Where: $\Delta A$ = is the change in cross-sectional area
D = Is the conduit diameter
$p$ = Is the pressure change
E = Is the Young’s modulus of the combined conduit wall
$t$ = Is the wall thickness

We see that the change cross-sectional area is highly dependent on the conduit diameter and of course by the pressure change. Utilizing large diameter hydraulic hoses will introduce a large time lag to account for the “extra volume” needed to sufficiently expand and pressurize the hose or pipe.
This was also the case when moving into deeper waters. Following this trend, API stated maximum closing times in the regulations governing BOP control systems, API 16d. In this document it is stated under section 5.2.1 (API16D, JANUARY 2005):

“*The control system for a subsea BOP stack shall be designed to deliver power fluid at sufficient volume and pressure to operate selected functions within allowable response times. The control system shall have a closing response time not exceeding 45 sec.for each ram BOP. Closing response time for each annular BOP shall not exceed 60 sec. Operating response time for each choke and kill valve (either open or close) shall not exceed the minimum observed ram close response time. The response time to unlatch the riser (LMRP) connector shall not exceed 45 sec.*

*Conformance with response time specifications shall be demonstrated by manufacturer’s calculations, by simulated physical testing or by interface with the actual BOP stack.”*

To meet these requirements, the system designers looked at ways to lower the time used to execute a function. Two important system changes was implemented:

- Venting to sea
- Indirect hydraulic systems

Venting to sea meant that the hydraulic losses associated with “pushing” the vented hydraulic medium trough pipes and hoses all the way to the surface reservoir, was dropped. The hydraulic medium that up to now had been petroleum based, had to be changed out to water based , to reduce the harmful environmental effects of venting to sea. Water based BOP fluid consists of potable water with additives aiming at giving the fluid the right lubricating and corrosion inhibiting effects. In colder climates, like Norwegian waters, ethanol is also added to give the fluid the appropriate freezing temperature, avoiding hydraulic freeze up of the system.

In Norwegian waters there is established additional requirements with regards to venting of water based BOP fluid based on environmental politics. It is not allowed in planned non-critical operations, creating the need for a return path for the vented fluids back to the topside reservoir thus eliminating the time advantage of lower hydraulically losses associated with venting to sea.

### 9.2.2 Indirect hydraulic systems

A large diameter hose being pressurized tend to expand as mentioned earlier. The design philosophy behind indirect hydraulic system is that it uses only one operational hydraulic conduit connected to a bank of subsea accumulators. Depending on the system design, an electric or hydraulic signal is sent down to control valves located subsea, thus reducing reaction times. These systems are divided in two:

- Pilot operated hydraulic
  - Using Sub Plate Mounted (SPM) valves
- Electro hydraulic
  - Using solenoid valves

In this section, the pilot operated hydraulic system will be explained in more detail.

The pilot operated control system is based on:

- Transmitting hydraulic power down to the BOP through a large diameter conduit
- Hydraulic pilot signals are sent down smaller lines to pilot valves that in turn directs hydraulic power to the appropriate function

Following from equation 4 in section 9.2.1, a reduction in diameter will have a substantial impact on the change of cross-sectional area thus greatly reducing the associated time lag. Choosing to build the system this way also reduces the size of the umbilical going down to the BOP. A typical control umbilical is shown in Figure 57. The large diameter supply hose located in the center of the umbilical, give low hydraulic flow losses when used and can be used for all the different functions required to fully operate the BOP.


Figure 57: BOP control umbilical on pilot operated system(Vetco)

The difference is now that large parts of the control system now were out of reach of the subsea engineer. To increase the operative reliability, a duplicate of the control system with the possibility of switching between two identical subsea parts of the system, created the needed redundancy.

The system now consist of:

- HPU
- Master control panel with secondary panel situated in the accommodation unit
- Hose reels with supporting systems for running umbilicals
- Dual set of identical umbilicals called pod cables
- Dual identical control pod’s, housing the subsea control equipment
- End users

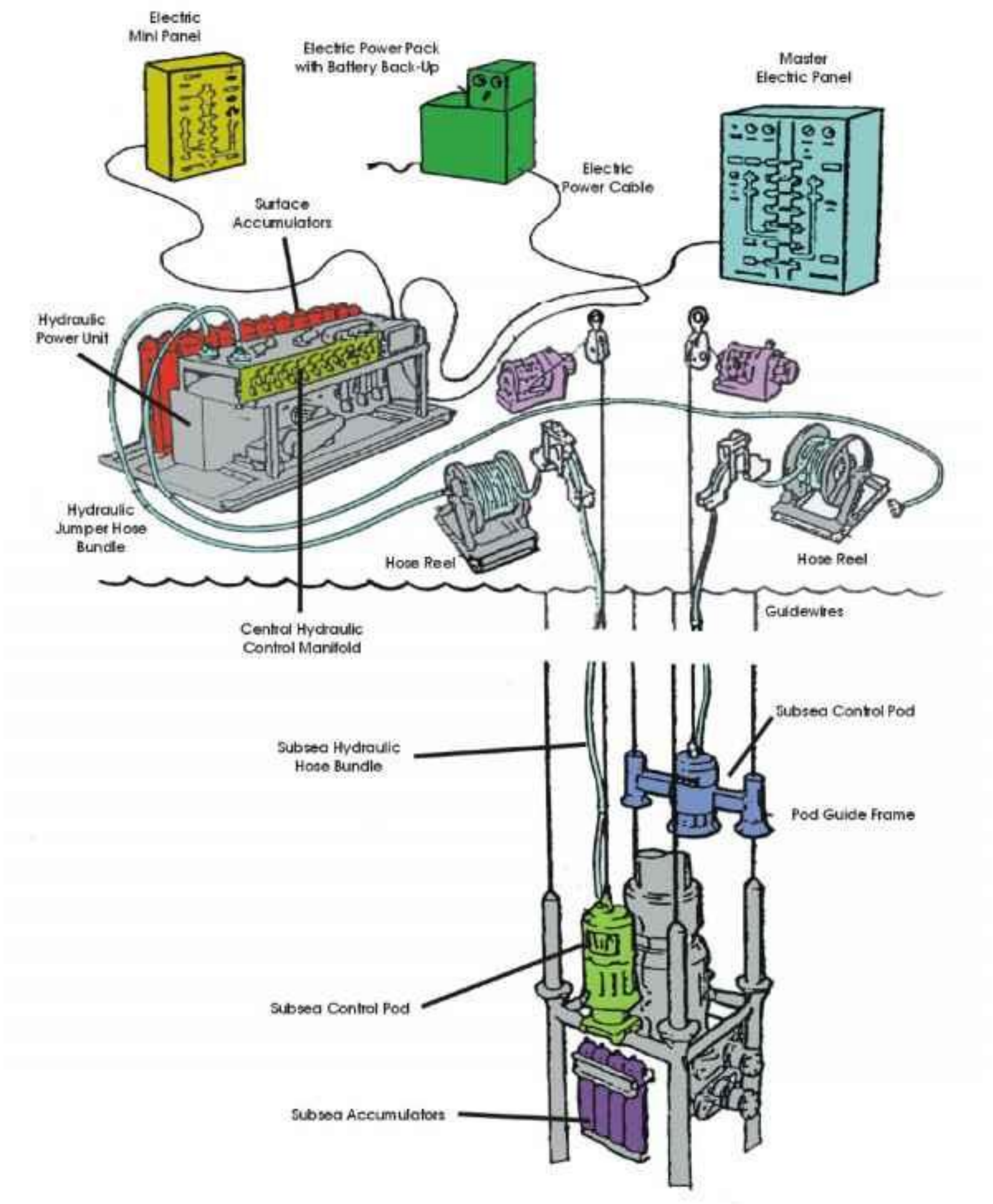



Figure 58: Pilot operated Control system(P.Potter, 2011)

The valves that the pilot hydraulic lines act upon are called Sub Plate Mounted (SPM) valves and there is one SPM valve for each hydraulic side of a function. A generic SPM valve is shown in Appendix 19. The SPM's are located in the control pods on the LMRP. A small hydraulic line can in this way control a much larger volumetric flow, thus allowing designers to increase system water depth compatibility, while still maintaining all onboard equipment handling and API time requirements. The system is vulnerable to contaminations in the BOP control fluid as they will degrade the SPM vales and shuttle valves capabilities to seal due to the impurities hindering a 100 % contact face on the seal surface of the components.

Summing up, the design has its limitations which are closely connected to the reaction times as water depths increase. This created the need to eliminate the time lag experienced with the hydraulic signal transfer. Recent developments in umbilical design have given room for claims that pilot operated system can, under some circumstances, operate within the API requirements up to 10000 feet(3048 meters)(P.Potter, 2011)

The pilot operated system is widely used in the industry today and will continue to be used due to its established technics and known design. It is in most aspects possible to do most of the maintenance and smaller modifications onboard by a skilled subsea engineer due to the systems low complexity level and well-known mechanical functions that are the foundation of the design

Pros:

- Simple "comprehensible" design
- Relatively cheap
- Can handle a large number of subsea users

Cons

- Water depth limitations
- Only hydraulic connection between subsea and topside, no data transfer
- Rely on SPM valves and is therefore vulnerable to control fluid contamination

### 9.2.3 Multiplexer control system

As the industry moved into even deeper waters with harsher well environments like for example high pressure and temperature wells (HPHT), the hydraulic time lag became a limitation. There was also a market for monitoring temperature and pressure on several sensors in the subsea stack at the same time. The pilot operated system allows for read back of pressure, but no data signals is transferred due to the pure hydraulic connection between the topside equipment and the subsea stack. This is where the multiplex system becomes attractiv. Multiplex BOP control was first introduced in 1976 (A.N. Vujasinovic, 1988) and have gone through 5 design modifications and is now on a 6$^{th}$ generation, implementing new technology to improve system reliability and performance.

The multiplex control system is often referred to as the MUX system. A multiplexer is defined as(wikipedia, 2011):

*"Multiplexer is a device that combines several input information signals into one output signal, which carries several communication channels, by means of some multiplex technique"*

This is a good way of describing the actions undertaken by the system as we want to control several aspects of the operation of a modern BOP. The range of signals varies from hydraulic operations to pressure read backs, temperatures, TV-signals, stresses, positions etc.(API16D, JANUARY 2005). The nature of the signal can therefore be of a diverse origin, however, all the information is modulated to electronic signals and sent via fiber cables from the vessel to the subsea equipment where the signal is interpreted. When a command is received subsea, a verification signal is sent back to the surface equipment so that errors in the command can be detected. When the surface equipment receives the correct verification signal, a last execution signal is sent down again and the action is performed. The use of fiber optics gives us a signal transfer time that is negligible, enabeling close to unlimited real-time monitoring possibilities. This means that the signals can be sent back and forth for verification thus almost eliminating the MUX process as an error source without time lag being added.

In Figure 59, a MUX umbilical is shown. The cable on the picture measures 1" in diameter. This is relatively small compared to pilot operated BOP umbillicals. This reduction in pod cable dimensions reduces the overall system dimensions on topside cable reels and supporting equipment for running of the cables. Conventional electric power cables can be seen alongside fiber optic cables as the information carrier.

**Figure 59: MUX cable(Umbilicals-International)**

As seen in Figure 59, the MUX cable has no hydraulic conduit. The hydraulic pressure is delivered subsea by riser auxiliary lines as mentioned in Section 3.1.2. This is rigid pipe with much lower expansion rates that the flexible conduit used in umbilicals. The hydraulic riser line is connected to a subsea bank of accumulators to minimize the response time from execution signal to process completion subsea. A generic MUX setup is shown in Appendix 20.

The MUX system uses similar components as the SPM valves but these are now driven by electric signals received from the subsea MUX control pods. They are named differently by each manufacturer, but will in this document be referred to as Direct Drive Valves (DDV's) a term used by NOV/Shaffer.

The BOP stack after the DDV's can be, and often is, similar to a pilot operated stack, but are now not limited by the need for dedicated pilot lines to facilitate a function and can therefore increase the subsea users as wished. As mentioned, sensors that feed the system with pressure and temperatures can now be utilized for a better understanding of the operational situation subsea. This is a great advantage as it will increase the understanding of the process involved in real-time, providing a powerful tool in the work minimizing the risks involved.

Pros

- Large reduction in size of hose bundles
- The need for subsea accumulators is lower as the rigid pipe has better characteristics and can deliver a quicker hydraulic response
- Dramatic quickening of response times
- Possible to transfer real-time diverse data over an information carrier

Cons

- Requirement for more auxiliary lines on riser
- More equipment mounted on LMRP
- Can be more costly in both the acquisition and operating phase due to high system complexity
- Will require a higher dependency on specialist workers for modification etc.

## 9.3 Conceptual control options

This section gives an evaluation of each of the control options intended to use on the concept and listed at the beginning of this chapter

The SIR will, independent of control scheme, need to perform the same mechanical and operational features. This give rise to assuming a more or less identical mechanical layout of the SIR itself with regards to hydraulic users and the pressure/vent requirements they impose. A simplified Hydraulic drawing is presented Figure 60. This will be the basis for the control needs. In addition to this there will be the need for energy storage subsea to gain a quick mechanical response when operating the equipment from a topside position. This is addressed first

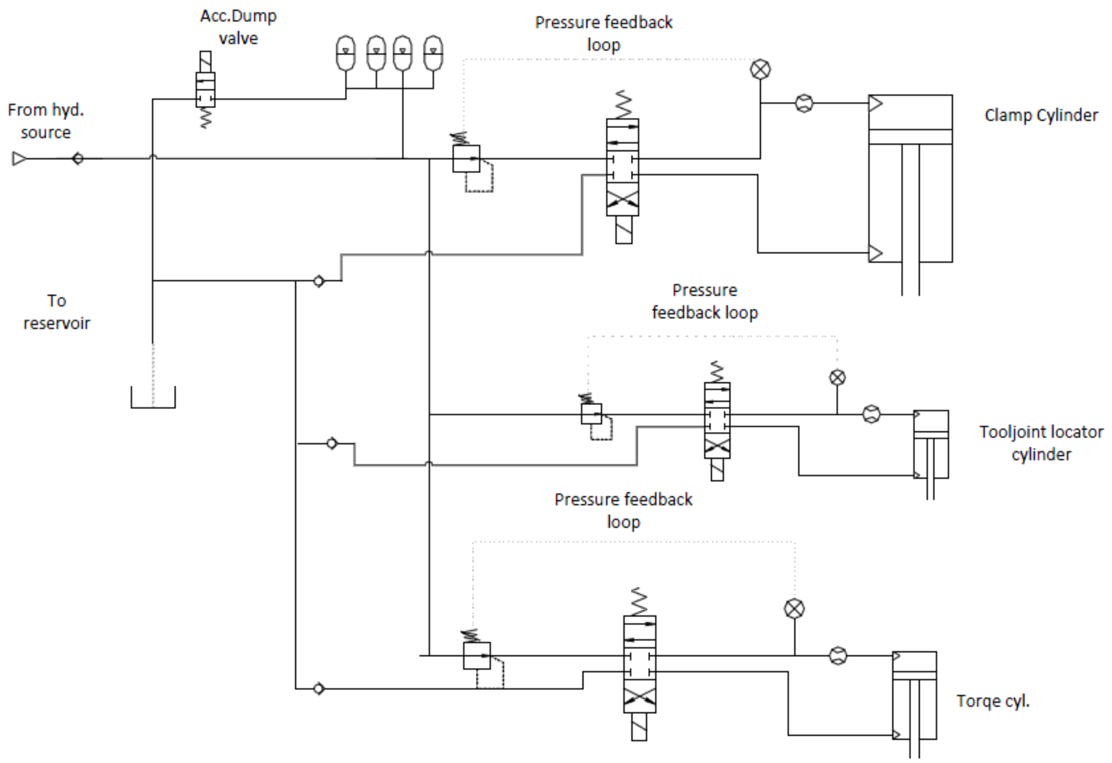



Figure 60: Generic hydraulic arrangement of the SIR

### 9.3.1 Energy storage subsea

Maintaining large enough quantities and availability of energy subsea have been solved in different ways throughout the offshore oil and gas industry's history. In this section a quick look at accumulators and batteries will be undertaken to see what possibilities there might be on the layout of our control system.

#### 9.3.1.1 Accumulators

The use of accumulator banks for subsea use has a long operational history. In recent years when drilling and operations have taken us into deeper waters, the attentions to accumulator performance has increased.

In Figure 61 the estimated useable volume of the accumulators is shown. It is clearly seen, that the available hy,draulic volume dramatically reduces at deeper waters. On BOP's ,API spec 16D and NPD both state safety margins on the available hydraulic volume which together with increased operational water depth leads to a very large accumulator bank subsea. Considering a standard 55 liter, 690 bar steel accumulator, one bottle weighs way 255 kg in air (A.S. Bamford, 2008). On a normal deepwater subsea BOP, the number of accumulator bottles in a complete BOP stack, can be in the range of

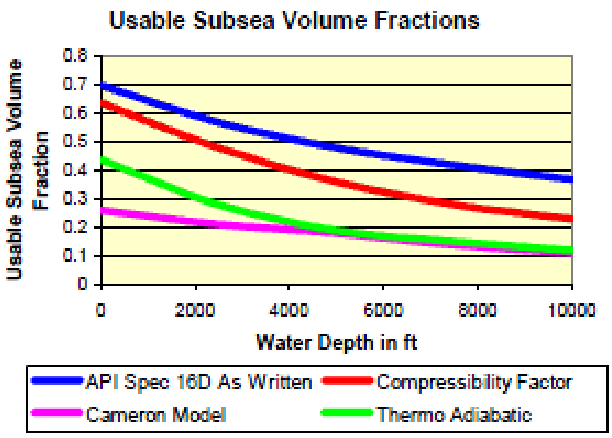



Figure 61: Usable accumulator volume (Sattler, 2002)

50-130. It can clearly be seen that the sheer size of the accumulators and also the weight of the bank can create unwanted side effects on the subsea system.

The favorable part of using accumulators is that it is a known technology familiar to the offshore crew and operational/maintenance engineers onshore.

#### 9.3.1.2 Batteries

The battery system has a long record of subsea use in oceanographic and submersible applications like petroleum production, BOP backup etc. The use of batteries as single source energy provider in our water depths, would not involve technical innovations (A.S. Bamford, 2008). There have been developed prototypes of all-electric BOPs capable of shearing tubulars, only using battery packs as energy source. The inherent energy in a battery pack is not effected by water depth at all, however, there are some factors that reduces available energy when considering batteries as energy source such as (A.S. Bamford, 2008):

- Low temperatures which will be experienced at deep waters and in the arctic might reduce the capacity with 20 %
- If the system is designed to operate with high current rates, the amount of energy that can be drawn from the battery might be reduced by 80%
- Batteries must be designed to deliver high current rates or damage to the internal parts of the batteries can be expected.

Some concern with the use of batteries relates to available energy to complete several operational sequences with the SIR. This thesis does not deal with this challenge in particular, but after reading several articles (A.S. Bamford, 2008), (Halvorsen, 2008) this is consider possible. Both directly high effect electric –hydraulic driven designs and a smaller low effect HPU charging a accumulator bank is looked upon as feasible by the author.

A significant weight and size reduction can be associated with the use of batteries compared to standard accumulators. Bamford's work concerning a shearing operation of tubulars estimated there energy need to be covered using 41 accumulator bottles weighing approximately 10,5 ton ,at the same time the energy amount could be replaced by 6 batteries of commercially available quality with a total weight of 204 kg. This was when considering ultra-deep waters and using standard accumulators of 55 liters. The size difference is illustrated in Figure 62.

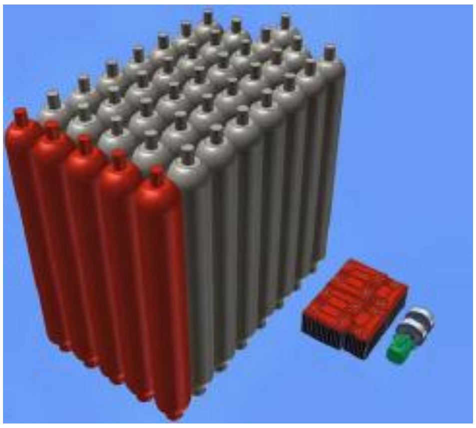


Figure 62: 41 Accumulator bottles versus 6 batteries (A.S. Bamford, 2008)

### 9.3.2 Use of existing BOP control system

In Section 9.2 an introduction was given to existing BOP control systems in use on the MODU fleet around the world. Our concept will in many ways require much of the same capabilities when it comes to applying a hydraulic pressure on the right side, venting the opposite side. But in addition to this we have the need to receive real-time monitoring of the process. This excludes a direct hydraulic and pilot operated system as an option, due to the fact that these systems do not facilitate transfer of data in the range that we will require. It might be argued that data can be sent via pressure pulses across a fluid conduit, but the maximal attainable data transfer rate using this method is not sufficient compared our needs. If we choose to build a control scheme based on an existing BOP control system, we are left with the mux system design as described in section 9.2.3

Regardless of how suited the mux design is to our operational task and design, we still have some challenges that will have to be dealt with while the concept is on the drawing board. To send the information to and from our equipment we need an information carrier e.g. a mux cable. If the drilling vessel is fitted with a version of a mux control system, it would be possible to use the existing cabling to send data, power and then leach from the hydraulic conduit with the use of a jumper hose from the LMRP to our system. This seams as an easy choice, but the practical side of this is exposed when taking into account:

- The exciting installed BOP control systems
    - On mid water and certainly on the NCS, pilot operated systems are common.
- The obtainable operational water depths using pilot operated control system and modern hose bundles can certainly exceed 5000 feet, with claims to up to 10000 feet (P.Potter, 2011), giving room for the use of this system on a large portion of the relevant wells

These aspects of our implementation process, will lead to a possible narrow marked as many of the rigs will have to change out their entire subsea control system These modifications would impose large capital expenditures and also require many days at quay taking place to adapt to our concept. An easier way around this problem would be to run a dedicated power and information carrier cable down to the SIR on vessels equipped with pilot operated BOP's.

In API 16 D, section 5.6.5 "Ancillary Subsea Electronics", the connection of additional electric equipment to mux systems is dealt with, in this section it is stated the following(API16D, JANUARY 2005):

*"The transmission of data and power for these types of functions may be through independent conductors in the subsea electronic umbilical or may be integrated into the main BOP Control System itself. When integrated as part of the main BOP Control System, detailed analysis and system integrity checking shall be performed to confirm the ancillary functions in no way impair, jeopardize, or degrade the purpose and operation of the BOP Control System."*

It is important to bear in mind that this section only deals with the connection of electro and data users, not hydraulic users.

Det Norske Veritas list the following in their governing rules concerning this topic, DNV-OS-E101 (DNV, 2011):

"*Where practicable, unnecessary hazards should be avoided or prevented through safe design such that further protection measures are not required."*

This is written in a section dealing with overall safety principles and by "*unnecessary",* it is interpreted as equipment or functions not contributing to increased overall safety.

In addition to the issues mentioned above, there is the increased operational risk when connecting additional equipment to a functional barrier. In the dialog with the Norwegian Petroleum Directorate (NPD), they have expressed concern with connecting a hydraulic user aiming for increased productivity, to the BOP hydraulic setup as a safety barrier.

One solution to this problem might be to connect the hydraulic pressure from the LMRP accumulator bank to the SIR.

To maintain the same level of operational and system reliability, the following measure might be applied:

- Sectioning the affected LMRP accumulator bank to reduce the effect of a worst case scenario
- Introduce two fail save valves between the accumulator bank and the SIR, on the LMRP side of the flex joint.
- One of these would be activated by the BOP control system, the other by the SIR. This would minimize the risk involved independent of BOP control system.
- Applying a small accumulator bank on the SIR to reduce reaction times.
- Increase safety factor on LMRP accumulator bank sizing

The regulatory concerns does in some way put limitations on the process of introducing a user, not contributing to well safety in the same manner as the existing components does, in the BOP/LMRP. Nevertheless, we intend to take this control option through our hazard analysis in the hope to identify which parts of the design that imposes a high risk on our system. It is the authors belief that industry regulators will ease their concerns, if the right measures are implemented and detailed information is presented showing the actual consequences of this auxiliary system. It can also be argued that this system will reduce hazards as a result of sheared pipe, milling and fishing as described in Section 6.1.2 and 6.1.3.

In this section the following is assumed:

1. The drilling vessel has installed a modern mux system
2. This system is capable of delivering our required power and data signals via the already installed mux cable
3. Hydraulic pressure is delivered from the accumulator bank on the LMRP.

4. Our conceptual equipment is mechanically, operationally and hydraulically capable of executing the procedure
5. Our equipment is placed as the first riser joint above the lower flex joint

The setup will then be as following:

- Lay down mux cables from the LMRP pod platform, up across the lower flex joint and into the control unit on the SIR.
- Lay down rigid hydraulic stainless steel pipe from existing LMRP accumulator bank, via flexible hydraulic hoses across the lower flex joint and into the SIR.
- A pair of flexible hoses should also go down again from the SIR to the control fluids return conduit so that vented fluid can be sent to the surface reservoir.
- It is assumed that all the valves and control equipment required to operate the SIR is located on a separate Subsea Control Module (SCM) placed on the SIR or LMRP.
- It is also assumed that all fluids are shared between the BOP and SIR and that these are water based fluids.
- Additional accumulators should also be installed on the SIR to maintain API/NPD required accumulator usable volumes as well as accumulator dump valves such that the accumulators pressure rating will not be exceeded when pulling the equipment up to surface again.

Electric power, data signals and hydraulic fluid is now delivered to support the operational needs on the SIR. The cost of this control option would be relatively low as the hydraulic infrastructure is present. The components that would make up the majority of development and production cost, would be:

- Dedicated SIR SCM
- Mux umbilical and reel cost on vessels using pilot operated BOP
- Topside control system for information sharing between topside and subsea components

Pros:

- Utilizes existing infrastructure for hydraulic pressure
- Relatively cheap
- Low system complexity

Cons:

- Shares hydraulic fluid with the BOP
- Additional equipment connected to BOP
- Requires pilot signal capability available in the umbilical to operate fail safe valve
- Increased chance for particle contamination of the BOP control fluid

### 9.3.3 Battery powered subsea HPU with acoustic link to the surface vessel

The use of underwater acoustics is known trough sonars, echo sounders etc. Acoustics have also been used for many years in the offshore industry in the form of an acoustic control system, controlling BOP functions and/or subsea production units. Kongsberg Maritime is a Norwegian supplier of such systems and has launched a system design called Subsea control unit 34 (SCU-34), capable of controlling 16 solenoid functions at the same time (Brevik 2011).

This is done based on Spaced Frequency Shift Keying. This technique provide a highly reliable communication form in noisy offshore environments which is often the case when numerous vessels operate in the same area in addition to noisy flowing well streams or other operations in adjacent pipes.

The SCU-34 is operable down to 4 000 meters in its standard dressing, but can be upgraded to operate at even deeper waters.

This control option is based on using only acoustic signals as data carrier. This is done with the transformation of data recorded/produced subsea, to acoustic signals sent out with the help of subsea mounted acoustic transducers mounted on the SIR and vessel. The signal is then read by transducers located on the drilling vessel, where it is once again transformed to the original data and is feed out to the relevant users onboard. The system is a two way communication system allowing the rig to send the same type of acoustic signals down to the subsea stack. The acoustic signals will not interfere with other acoustic devices such as (Brevik 2011):

- Acoustic BOP emergency control system
- Drilling/support vessel Positioning
- Sonars

As mentioned, the SCU-34 is capable of controlling 16 solenoid signals; it can also facilitate 8 analog sensors. This can be expanded too. The amount of sensors and valves required for our design is not seen by Kongsberg R&D as impossible to incorporate in either one or a combination of two SCU-34 modules, this is shown in Figure 63.

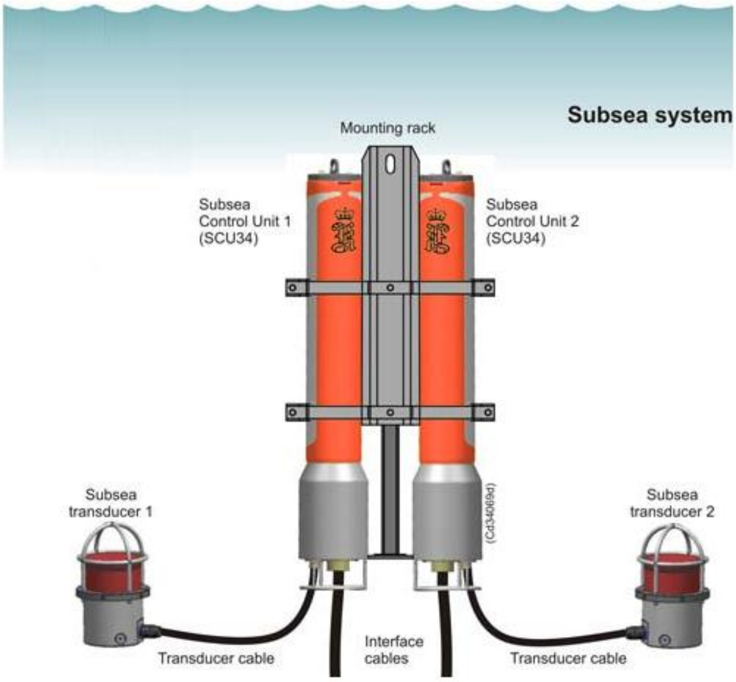



Figure 63: SCU- 34, shown with to modules(Kongsberg, 2011)

Hydraulic pressure and flow is delivered by installing a subsea HPU with a sealed pressure compensated reservoir located subsea. This reduce hydraulic losses associated with venting to a topside reservoir and gives a closed hydraulic circuit with minimal negative environmental effects, usable on the NCS and typically in the Arctic region.

The subsea HPU will consist of an electric motor connected to a pump unit, typically based on pistons, to reach the high pressures required to operate our system. The electricity needed to power the HPU motor is stored in subsea battery packages which can be changed out while the equipment is on the surface.

The subsea HPU design can be either:

- High pressure and low volumetric capacity with low current batteries, connected to a accumulator bank. The size of this bank would be highly dependent on the operational water depth and the hydraulic volume required to complete the operation.

- High pressure and high volumetric capacity with high current rates drawn from the batteries. This system could be connected directly to the users, via DCV's, thereby saving accumulator weight.

The design choice will affect the type of batteries used and will be dimensioning for the electric system, as higher current rates will require larger cabling and high current components.

The most favorable advantage by utilizing this design is the elimination of

- Additional umbilicals
- Clamping of umbilicals to guide wires or similar mechanism to fixate them when installed
- The need for sheaves to guide umbilicals
- Hose reels with control and mechanical power
- Deck/storage area for the reels
- Topside HPU

We have in other words a standalone unit capable of lying dormant with no mechanical or operational effects on the other subsea systems until it the operation will require it purpose.

The acoustic control option has been discussed and looked at in collaboration with representatives from Kongsberg Maritime, Subsea Division. Controlling this type of complex operation through acoustic link only, have never before been carried out and gave us some challenges:

- No electric power is fed to the subsea equipment, this means that all energy must be stored and available subsea.
- Time lag from vessel to subsea user and back.
- Data bandwidth

To give the users a possibility of energizing the system after use, the design would have to incorporate a ROV landing platform used for ROV recharge of the batteries, system diagnostics and test etc. This will increase the physical size of the design and give a larger drag force when operating in waters with high current velocities.

One of the greatest challenges will be the time lag that will be experienced when sending and receiving signals. As sound propagates in water, the speed is dependent on the water properties such as temperature, salinity, pressure i.e. water depth. In seawater the speed varies from ca. 1 480 m/s to 1 600 m/s, but as shown on the velocity profile in Figure 64, a mean value will be around 1500 m/s. This will introduce a time lag of 2 seconds each way the signal travels when looking at a 3000 meter operational situation. Adding this, the required time to process the signals and send a read back signal, a total of 5 seconds can be expect, from sending to feedback signal is received. This forces our design of the control system, from real time to sequential operation of the equipment. Not necessarily the worst direction to take, but it will mean that torque-turn graphs and other monitoring wishes will not be given to the users before after the operation is completed. This reduces the operator's possibility to intervene if errors are spotted.

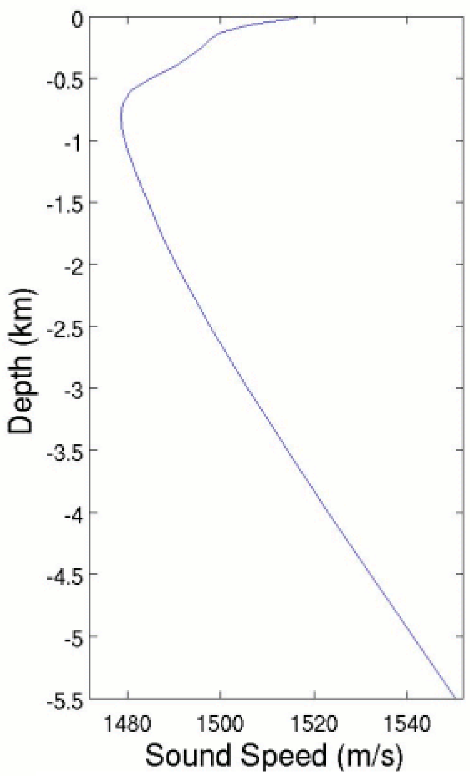


**Figure 64: example of sound velocity profile in salt water(wikipedia, 2011)**

The data bandwidth available is also limited. Theoretically the SCU-34 can operate at 8 kB/s , however, the signal is reduced to typically 4-5 kB/s on 500 meters of water depth and down to around 1 kB/s on 4000 meters(Brevik 2011).

This, in turn, puts restrictions on the amount of data being feed to the operator so that additional time lag is not created.

The technology needed to construct a pressure compensated closed subsea HPU system is today available but at a very high development and production cost. Similar systems used for well control by FMC subsea on producing subsea well have a first unit cost, including tests, certification, and prototypes of approximately 40 mil NOK. The subsequent units will have a pure production cost of 10 mill NOK. The system is more advanced then what we need and the governing classification and certification is more comprehensive. We can therefore expect a lower cost on our system, the estimate shows however, the price range that this equipment will be in.

A system designed around a battery powered subsea HPU with an acoustic link to the surface vessel would consist of:

- Acoustic transducer on rig
- Acoustic transducer on pup joint
- Subsea control unit
- Battery package
- Subsea HPU
  - Electric HPU motor
  - Hydraulic pump unit
- Subsea reservoir
- The standard hydraulic setup using rigid pipes, DCV and pressure reducing valves.

The acoustic side of the system would have a price tag from 500.000 to 1.000.000 NOK. This would include

- Acoustic transducers subsea
- One mobile topside transducer
- Sensor interface
- Batteries to support the acoustic control unit
- Oil filed cables
- Software to topside control via operator PC.

The positive and negative sides of a system based on using a battery powered subsea HPU with acoustic link to the surface vessel can be:

Pros:

- No additional umbilicals
- No clamping of umbilicals to guide wires or similar mechanism to fixate them when installed
- No need for sheaves to guide umbilicals
- No hose reels with control and mechanical power
- No deck/storage area used
- Separate hydraulic system from the BOP

CONS

- High cost level
- Weight due to the accumulated equipment needed to support the SIR
- Size will increase drag force
- High system complexity
- Requires extensive maintenance surveillance

### 9.3.4 Separate hydraulic conduit and electrical cable to the surface vessel

Separate hydraulic conduit and electrical cable to the surface vessel will introduce a standalone control system using flexible cables with hydraulic pressure hose, communications carrier and electric power, almost like the equipment seen on pilot operated BOP control systems but with the addition of data communication in the umbilical. Otherwise it can use the combination of a rigid hydraulic conduit and a flexible cable with only communication and electric power cabling, more or less the same setup as can be seen on a MUX BOP control system. All of the components linked to control is then assumed to be fitted to the SIR riser pup joint.

The first option will, based on the needed diameter of the cables; need large hose reels placed in a already cramped cellar deck area. If the system is designed to work on ultra-deepwater wells, the size of the reels will grow accordingly. Retrofitting such large components will require the construction of new deck platforms, designed to give extra deck space in the cellar deck area. The need for a special designed umbilical, large powerful hose reels and new reel platforms will increase the capital expenditures to a high level. It might also be a challenge to find the needed volume on smaller drilling vessels to fit such large singular components. Basing the control design on a flexible hydraulic conduit will introduce large time lags and will have to be compensated by an increase in accumulator bank capacity subsea. This will add to the total system weight.

The second option, using rigid auxiliary riser pipes, reduces the umbilical diameter and gives us a fair chance of installing a smaller hose reel on an existing deck space around the moon pool. Contributing to increased expenses is the need to install additional auxiliary riser pipes. These pipes are of a stainless steel material grade and will have a high cost. It can only be installed on risers that have available spare slots in their riser flange.

On the NCS there will be the additional requirements of routing the vented hydraulic fluid back to a surface reservoir. Connection to the already existing hydraulic return line on the subsea stack is feasible and is baked into the assumptions in this design. Nevertheless our system will then consist of:

- Reels for umbilical
- Hydraulic conduit from vessel
- Control and electric cable from vessel
- Subsea Control Module on SIR
- DDV's to control hydraulic users
- The standard hydraulic layout
- Check valve and transfer pipe to hydraulic venting

The positive and negative sides of a system based on using a battery powered subsea HPU with acoustic link to the surface vessel can be:

Pros:

- Simple
- Known technology
- Will work

Cons

- Additional hose reels
- Additional umbilical
- High weight due to accumulators
- Large drag force due to size
- Umbilical running will increase BOP running time
- Interface with existing BOP control system on the vent side

### 9.3.5 Accumulator based energy stored subsea with acoustic link to surface vessel

The challenges connected to using acoustics as the main communication carrier has been described in section 9.3.3. With the knowledge that the aim is to design a system capable of operation on ultra-deepwater wells, and the statement made about accumulator usable volume vs. water depth made in section 9.3.1, the following can be deduce:

To be able to perform repeated operational sequences with the SIR without hydraulic recharge by the ROV, the size of the accumulator bank would grow rapidly with water depth. The ability to run the operational sequence several times, is seen as highly advantageous, as there most likely will be situations where this will be required.

This would make the subsea stack larger both when considering stack weight and fluid drag forces. This increase in weight and drag forces would have a negative impact both on the riser forces while running and retrieving BOP and on the wellhead forces while in operation. The combination of, weight and size of such a bank gives this control option several negative attributes reducing the allover system feasibility to such a degree that further analyses will not be undertaken by the author.

### 9.3.6 Subsea HPU with multi-adaptable control and power connections

When describing and analyzing the control concepts listed above, it became obvious that there was in particular one design feature that increased system risk and to some degree an assumed lowering in overall system reliability, namely the shared hydraulic fluid with the BOP. It was therefore given extra effort to develop a control concept that would utilize a separate hydraulic system, while at the same time keeping the expenses at a minimum. Looking at the use of electronic and electric equipment on MUX BOP control systems, a decision was made to try to utilize the already existing power and control capabilities.

Such a system may consist of:

- MUX control pod Interface/separate cable run from vessel
- Battery package
- Subsea HPU
    - Electric HPU motor
    - Hydraulic pump unit
- Subsea reservoir
- Subsea control unit with DDV's(see section 9.2.3), mounted on the riser pup joint
- The standard hydraulic setup using rigid pipes, DCV and pressure reducing valves.

This solution will allow us to connect to the MUX system when the vessel is equipped as such. It also gives the opportunity to have the exact same control and monitoring capabilities on vessels equipped with pilot operated BOP's. This is then done by running a small additional low voltage electrical and fiber cable. This can be secured and clamped in the same manner as the BOP control pod cables are clamped, using modified pod cable clamps such that they hold two cables instead of the traditional one cable clamp.

This will lead to a minimum of additional installation/retrieval time and keep the work over open sea to a minimum.
The cable must be spooled on a small reel, but the diameter will be much smaller than 1" and the reel footprint is therefore considered to be small.

The above stated system layout will give us a large user group as the system can be installed with little or no rebuilding on rigs using MUX, and with some small scale retrofitting on vessels using pilot operated BOP's.

The system layout is considered very favorable from a risk point of view; however, considering the utilization of the pressure compensated closed hydraulic system with a subsea HPU, the cost will be very high. This will affect the development, production and operational cost of the whole system.

## 9.4 Comparing the different control systems

To select the best design for the conceptual needs it is necessary to take into consideration a variety of aspects. Cost, operational reliability and of course the risks involved must be understood and compared. With our solutions consisting of new designs, little or no historical data on failure rates and failure modes has been documented. Different approaches to look into the operability and reliability were therefore considered. All of the approaches have the same main goal namely to uncover the undesirable occurrences inherent in each design. We will first go through the methods that might be used on this particular problem(Rausand and Utne, 2009):

- Preliminary Hazard Analysis(PHA)
- Hazard and operability study (HAZOP)
- Failure mode, effects, and criticality analysis (FMECA)

The PHA is a method normally applied in an early design phase of a component or system. Originally developed by the US Army, it has gained recognition in a diversity of industries and aims at mapping undesired hazards, threats and events early in the design phase. The findings can then be integrated in the design of the system eliminating, reducing or adding mitigating measures to components or systems prone to critical failures. The method is often used when only the main components of a system are selected and detail information is not available.

The HAZOP method was originally developed by the process industry and as a systemized creative method uncovering deviations in process plants. The method is based on groups of selected persons with detailed knowledge on different aspects of the system in question. The group uses guide works to systematically look for consequences of deviations from the design intent. The method is often used to analyze work procedures and to find new undiscovered failures and consequences. The HAZOP is concerned with identifying possible deviations from the design intent and then proceeds in two directions, one to find the potential causes of the deviation and the other to deduce its consequences.

FMECA is originally a reliability analytical method developed to uncover component failures in technical systems. The method starts with a possible component failure and then proceeds to investigate the consequences of this failure on the system as a whole. Thus the investigation is unidirectional, from cause to consequence (IEC, 2001)The method often require more detailed information on failure rates, modes etc. to become effective in its use. It is therefore often used when the first draft of detailed components is selected and component history available.

The selection of the right method was discussed on several occasions with Professor Svein Kristiansen at the institute of marine technology, NTNU. After carefully examining the system that is to be analysed and the data/information available the decision was made to perform a PHA analysis as this would be the most correct method giving useful information on the different designs. It would also give a way of discovering what risks that could be designed out of the systems and which could not.

## 9.5 PHA analysis of the different control options

To get a good insight of the underlying methods in a PHA analysis several sources was used:

- Maritime Transportation-safety management and risk analysis by Svein Kristiansen
- Risikoanalyse-teori og metoder by Marvin Rausand and Ingrid B. Utne
- The ISO 14121-1 standard- Safety of machinery – Risk assessment

In addition to this, several books on hydraulic systems where used to go into the depth of the normal problems in relation with hydraulics. These where:

- Hydraulics and pneumatics by Andrew Parr
- Oljehydraulikk by Arne Kjølle
- Oljehydraulikk by Steinar Haugnes

With the theoretical and methodical foundation now in place, the system or analysis boundary must be established.

As assigned, the analysis should try asses the overall system safety of the proposed control concepts. This will not include mechanical design of the cylinders, jaws, riser pup joint, but will to some extent include the operational procedures as they are affected by the communication and control method chosen. It is assumed that the system is operated by trained professionals and that all the mechanical aspects of the concept are operational to the level needed to maintain the design intent. The PHA analysis gives an assessment on the frequency and the consequence of each entry. This is done by ranking them between one and five on the basis of the following criteria's(Rausand and Utne, 2009):

| Class | probability | Frequency |
|---|---|---|
| **1** | Very unlikely | Less than one occurrence each 1000 year |
| **2** | Remote | one occurrence each 100-1000 year |
| **3** | Occasional | one occurrence each 10-100 year |
| **4** | Probable | one occurrence each 1-10 year |
| **5** | Frequent | More than once a year |

Table 18: Frequency classes

| Consequence class | For humans | For assets | For the environment |
|---|---|---|---|
| 1 | Small personal injury | Less than 200 000 NOK | Small impact, short recovery time |
| 2 | Serious personal injury | 0,2-2 million NOK | Large impact short recovery time |
| 3 | 1-2 deaths | 2-20 million NOK | Some impact Long recovery time |
| 4 | 3-10 deaths | 20-200 million NOK | Large impact Long recovery time |
| 5 | More than 10 deaths | More than 200 million NOK | Large impact Permanent damage |

Table 19: Consequence classes

It is important to bear in mind that the classes are large and the inherent variations in risk are thereby also big. The assessments of the consequences and frequencies have been based upon the author's system understanding and discussion with co-engineers. It is not in any shape or form a complete system analysis, but merely a way of pointing out the pitfalls in a proposal and the way around it, if possible.
To visualize the assessed risk, a risk matrix is used. This has frequency and consequence along to of its axis. The numbers in the matrix is the sum of the combination of the frequency and consequence class.

| consequence class | | | | | |
|---|---|---|---|---|---|
| 5 | 6 | 7 | 8 | 9 | 10 |
| 4 | 5 | 6 | 7 | 8 | 9 |
| 3 | 4 | 5 | 6 | 7 | 8 |
| 2 | 3 | 4 | 5 | 6 | 7 |
| 1 | 2 | 3 | 4 | 5 | 6 |
| | 1 | 2 | 3 | 4 | 5 |
| | Frequency class | | | | |

Table 20: Risk matrix

Green area - Acceptable risk, consider ALARP measures

Orange area- Acceptable risk but ALARP measures are required and further investigation should be considered

Red area- Not acceptable risk level, risk reducing actions are required

The number in the risk matrix is called the risk index number (RIN) and is a number from 2 to 10 where 10 is the one affiliated with the highest risk. To classify the risk, a principle called “as low as reasonable possible” (ALARP), is used. This is a way of classifying risk into:

- Tolerable risks
- Tolerable –if the utility value of the activity is seen as high and all reasonable risk reducing measures are in place
- Intolerable risk.

The principle is used when going through new or existing designs. If findings are made in the intolerable area, redesign or other actions have to be done before startup of the activity or system can be initiated. In the ALARP zone, the orange zone in the risk matrix, all reasonable mitigating, or frequency reducing measures must be put in place. The overall goal of the ALARP process is to move the findings into a lower RIN number class and if possible, get them into the green area of the risk matrix. The risk mapped in the lower risk/green area, can be improved if this is proven cost beneficial. More information on the ALARP principle and process can be found in the book “Risikoanalyse-teori og metoder” by Marvin Rausand and Ingrid B. Utne(Rausand and Utne, 2009)

Independent of the control concept in question, the SIR would have the same control needs. It was therefore set up an input function and output overviews for the SIR de-torque and torque process. This can be seen in Appendix 21 and Appendix 22. This gives us insight into the process at hand and the flow of information to and from the vessel/SIR.

The subsequent analysis of the system is divided into the number groups shown in Table 21 :

| Number series | Deals with |
|---|---|
| **100-…** | General hydraulic control/layout |
| **200-…** | hydraulic, control and electric power from existing MUX system |
| **300-…** | subsea battery bank |
| **400-…** | Subsea HPU |
| **500-…** | Acoustic communication |
| **600-…** | Dedicated umbilical from vessel to SIR |
| **700-…** | Recharge of energy subsea with the use of ROV |
| **800-…** | Only power and control from BOP MUX system |

Table 21: PHA number classes

This number refers to the number found on each entry in the PHA appendix.

As mentioned in Section 9.3 the basic hydraulic layout and control/monitoring needs are the same for all the control concepts. The analysis of this part of the system is done with reference to Figure 60

The complete PHA is attached in Appendix page 98 to 98

The number of RIN class entries for each system is listed in Table 22.

| | Consisting of number series | Number of entries | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| RIN class | | *1* | *2* | *3* | *4* | *5* | *6* | *7* | *8* | *9* | *10* |
| **Use of existing BOP control system** | 100, 200 | 0 | 1 | 2 | 13 | 11 | 20 | 15 | 4 | 0 | 0 |
| **Battery powered subsea HPU with acoustic link to the surface vessel** | 100, 300, 400,500 | 0 | 2 | 11 | 17 | 12 | 30 | 21 | 4 | 0 | 0 |
| **Separate hydraulic conduit and electrical cable to the surface vessel** | 100,600 | 0 | 1 | 2 | 13 | 7 | 19 | 12 | 3 | 0 | 0 |
| **Accumulator based energy stored subsea with acoustic link to surface vessel** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Subsea HPU with multi adaptable control and power connections.** | 100, 300, 400 | 0 | 0 | 2 | 13 | 9 | 18 | 11 | 3 | 0 | 0 |

Table 22: RIN observations in the different systems

It is shown that systems with a high degree of complexity have potentially more hazards in the designs currently drafted.

## 9.6 Control system conclusion

The different control approaches have now been presented and a PHA is carried out to map initial hazards in the design phase. The decision on which control system to use should be based on:

- Allover system safety
- System reliability
- Ability to fulfill the control and operational needs
- System complexity
- Development costs
- Operational costs
    - Maintenance cost
    - Increased operational time

Taking all of the above into consideration based on the information obtained writing this thesis, carrying out the PHA and discussions with industry representatives, the control method based on using the existing BOP infrastructure emerges as the best solution. This is the option described in section 9.3.2 and is based on using hydraulic capacity from enhanced LMRP accumulator banks. Electric power and control is obtained by dedicated cable on pilot operated BOP's and by connecting to the existing MUX BOP control system when possible. This option is also considered as the best control system by industry representatives.

# 10 Discussion of obtained results

In this thesis several assumptions are made and used as a basis for further decision making. These are clearly stated as assumptions in the text. Some of the inherent assumption weaknesses and other details that require additional information will be stated in this chapter.

- The frequency of emergency disconnect sequence is in Section 6.2 assumed to be 0.01 on each well. This is assessed by the author, as a somewhat high. The consequences of lowering this probability to 0.001 will however, not affect our end results significantly.
- In Section 6.1.1.1 a tripping speed restriction was assumed due to bottom hole pressure variations. This assumption is assessed to be 200 meters/hour. This is not an industry standard and is stated only to get an extreme case.
- In the process of deciding which tool joint tong-spaces to adapt the machine to, large uncertainties with regards to tong space were uncovered. This will lead to less than optimal gripping contact surface to guarantee relative rotation of box and pin end.
- The empirical minimum clamp force obtained by Aker Solutions in chapter 7.1.2, is a result of a given contact area between the dices and the tong space on the TJ. As a result of the uncertainties with the TJ tong-space length, the dice contact area will be smaller than Akers industry standard. The obtained clamp force from Aker might therefore be too low in this case.
- The PHA was performed by a limited number of persons; this hinders the uncovering of all aspects of the system and might introduce hazard blind spots.
- The cost of operational failure is very high on these systems, this might explain why the entries in the PHA are all above 3 and why there is a predominance of entries in the 5-7 RIN area.
- In previous work, the placement of the components is discussed, with regards to putting them in the LMRP or BOP. In this thesis a vertical compact design is achieved, combined with the chosen control option based on using LMRP accumulators. Based on this, there is reason to believe that a second iteration considering placement of components in the LMRP should be undertaken. Industry input combined with a dialog with industry regulators, is needed to reach a conclusion on the preferred location.

# 11 Conclusion and further work

## 11.1 Conclusion

This report considers the challenges related to operating conventional drilling vessels in the Arctic. It is concluded that an increase in the frequency of disconnection of subsea drilling equipment, can be expected, based upon:

- the areas where floating ice features are relevant versus the locations of the potential hydrocarbons
- the water depths making possible with drifting icebergs
- the sum of uncertainties in weather forecasting
- wind as a driving force in floating ice features drift

Current methods of disconnection lead to a significant operational downtime. The time needed to prepare for an upcoming disconnection will also require ice management capabilities in the form of additional standby vessels. These factors undoubtedly increase the well cost.

The goal of this thesis is to investigate a new system and procedure which allows a quick disconnect and reconnect of the drill string and the marine drilling riser. The time for disconnection of drill string and riser should take place within 5 minutes.

Physical limitations onboard relevant drilling rigs are mapped and imbedded in the design requirements used to develop several alternative methods of quick disconnection of marine drilling riser. These methods are rated and one concept of using a subsea iron roughneck located above the lower flex joint is chosen. Resulting installation, operation and retrieving procedures are established.

The subsea iron roughneck's control and monitoring needs is addressed. Existing and conceptual control solutions are evaluated. Based on a preliminary hazard analysis, cost and system complexity, a control system built on the concept of utilizing existing BOP infrastructure, is chosen.

A reduction of 89-97 % in costs related to planned and unplanned disconnections is achieved.

## 11.2 Further work

- Placement of components should be re-considered with the option of placing the SIR in the LMRP. Industry input combined with a dialog with industry regulators is needed to reach a conclusion on the preferred location.
- A detailed study must be done into what torque will be held by a range of commercially available standard BOP pipe rams
- When upper torque limits on existing BOP rams are in place, a “safe” lowering torque must be established. This will be the torque that the SIR will set as a lower limit on the de-torque sequence performed when preparing to disconnect.
- Develop lifting yoke to ease rigging while assembling and disassembling in the moonpool area. The yoke should keep the modules in a leveled position and assist in the mating of the flanges, perhaps with the use of conical “soft material guide pins on selected bolted holes in the flange.
- Detailed hydraulic system development must be undertaken to establish final system costs.
- When the hydraulic system is known in detail, the control system can be developed.
- Fatigue problems should be addressed.
- The effects of introducing a new bending stiffness as the riser pup joint will be somewhat stiffer, should be mapped. Adjustment to stiffness values should be made if found necessary.
- The uncertainty in tool joint lengths should be addressed and operational data should be collected. If found necessary, redesign of the locational sequence should be performed using sensors to locate the transition between the two tool joint in question. The accuracy of using magnetic sensors imbedded in clamp cylinders should be studied.

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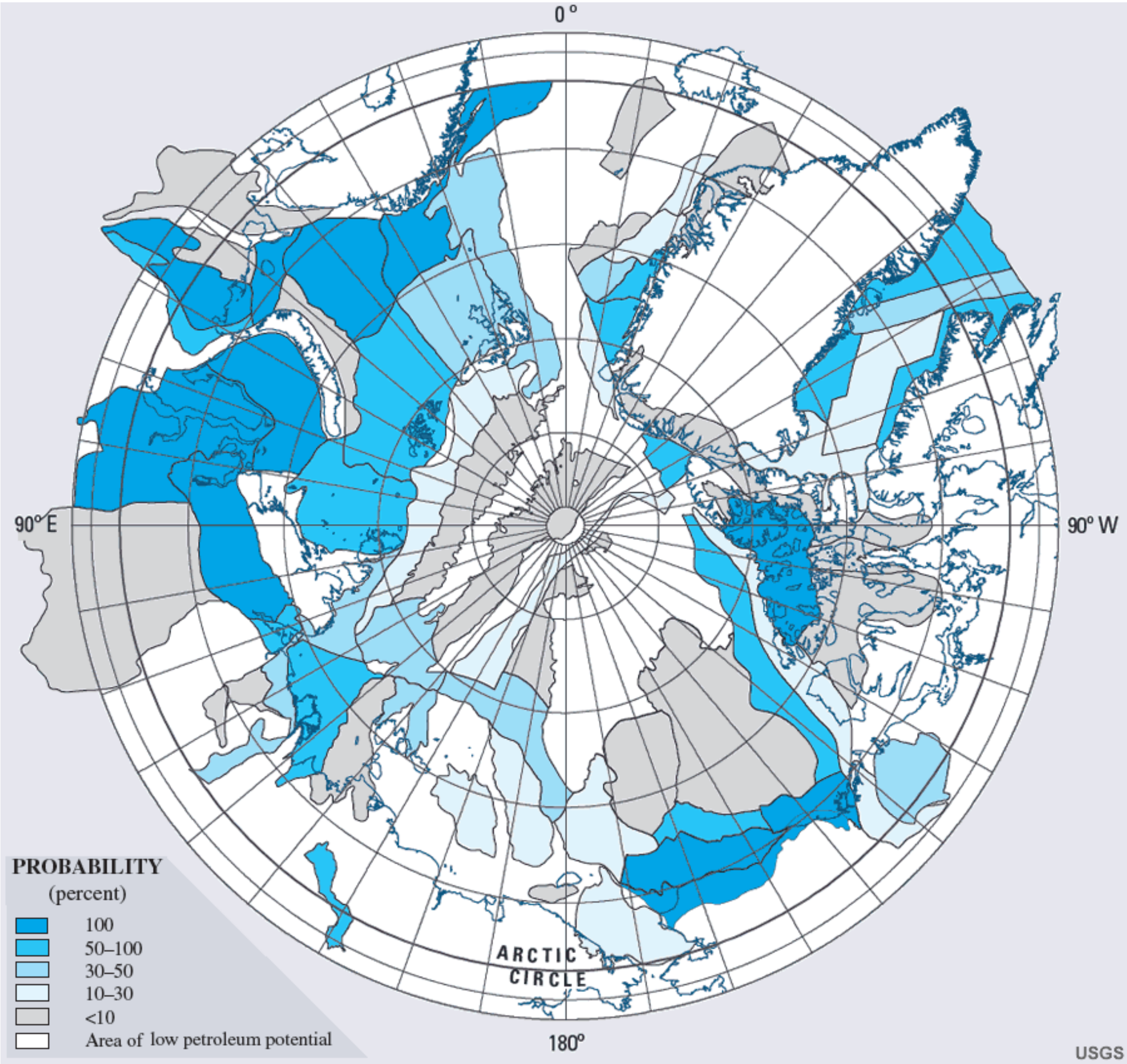
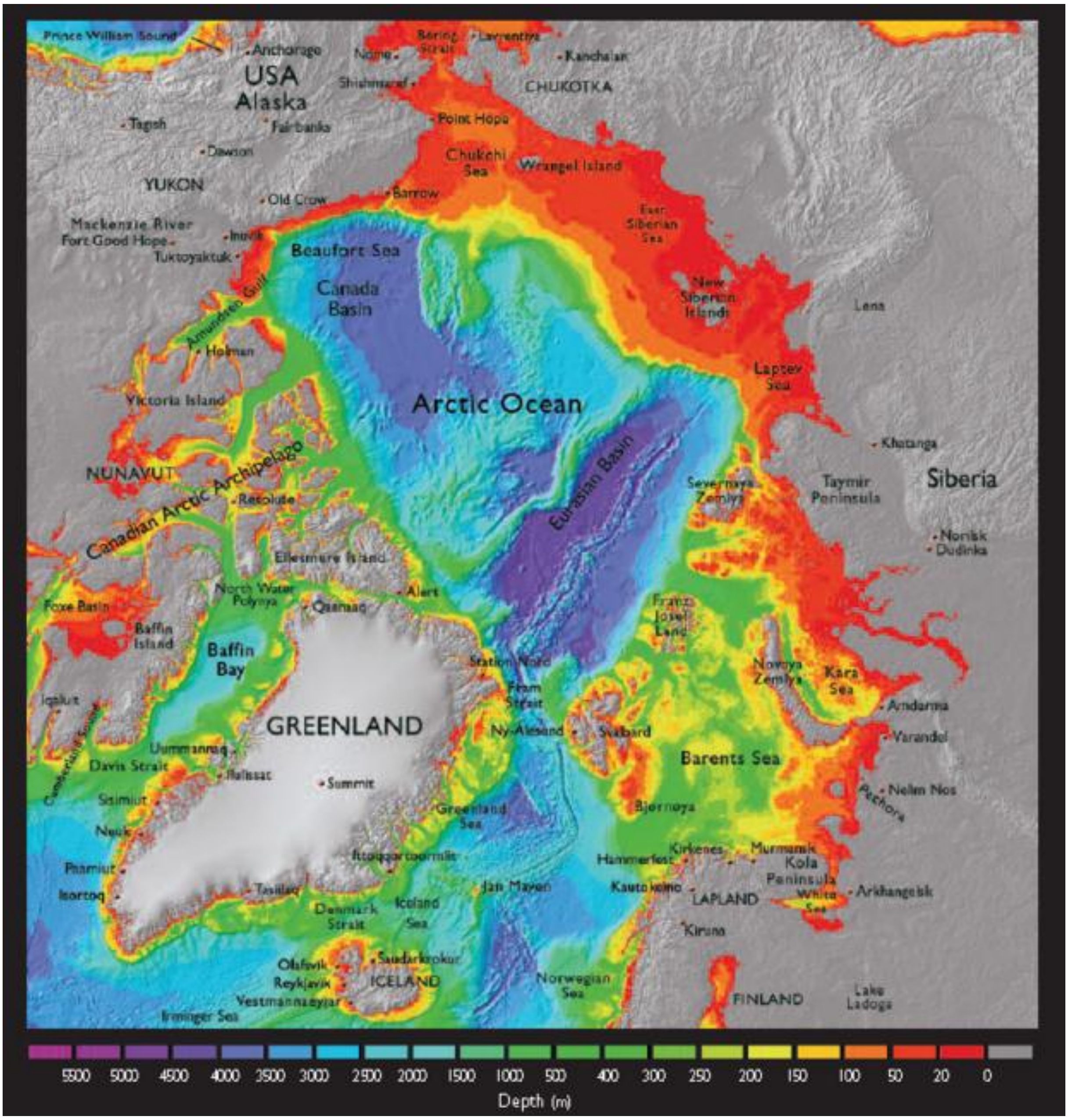
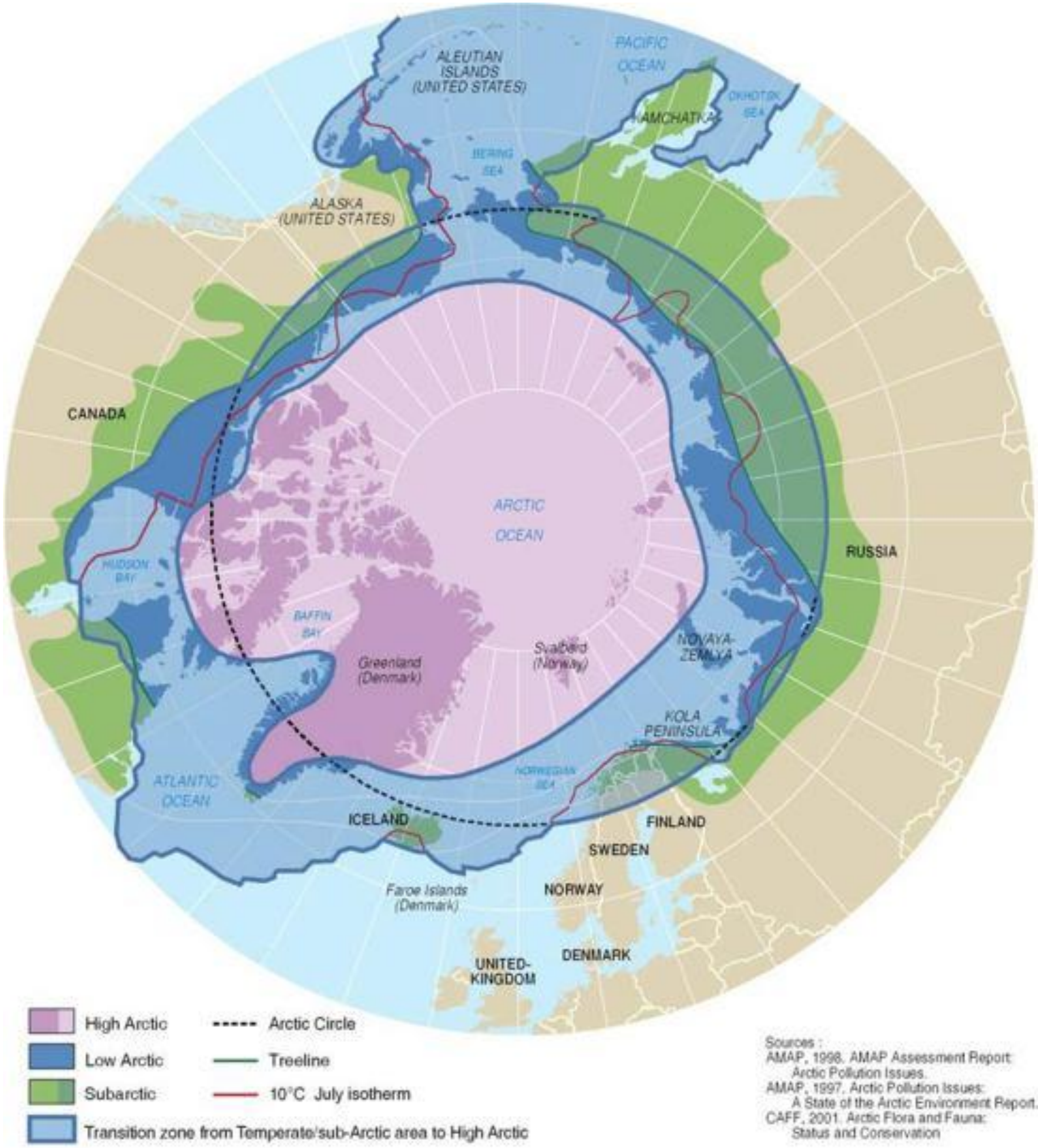
# Appendices




Appendix 1: Probability of the presence of at least one undiscovered oil and/or gas field with recoverable resources greater than 50 million barrels of oil equivalent (D. Gautier, 2008)

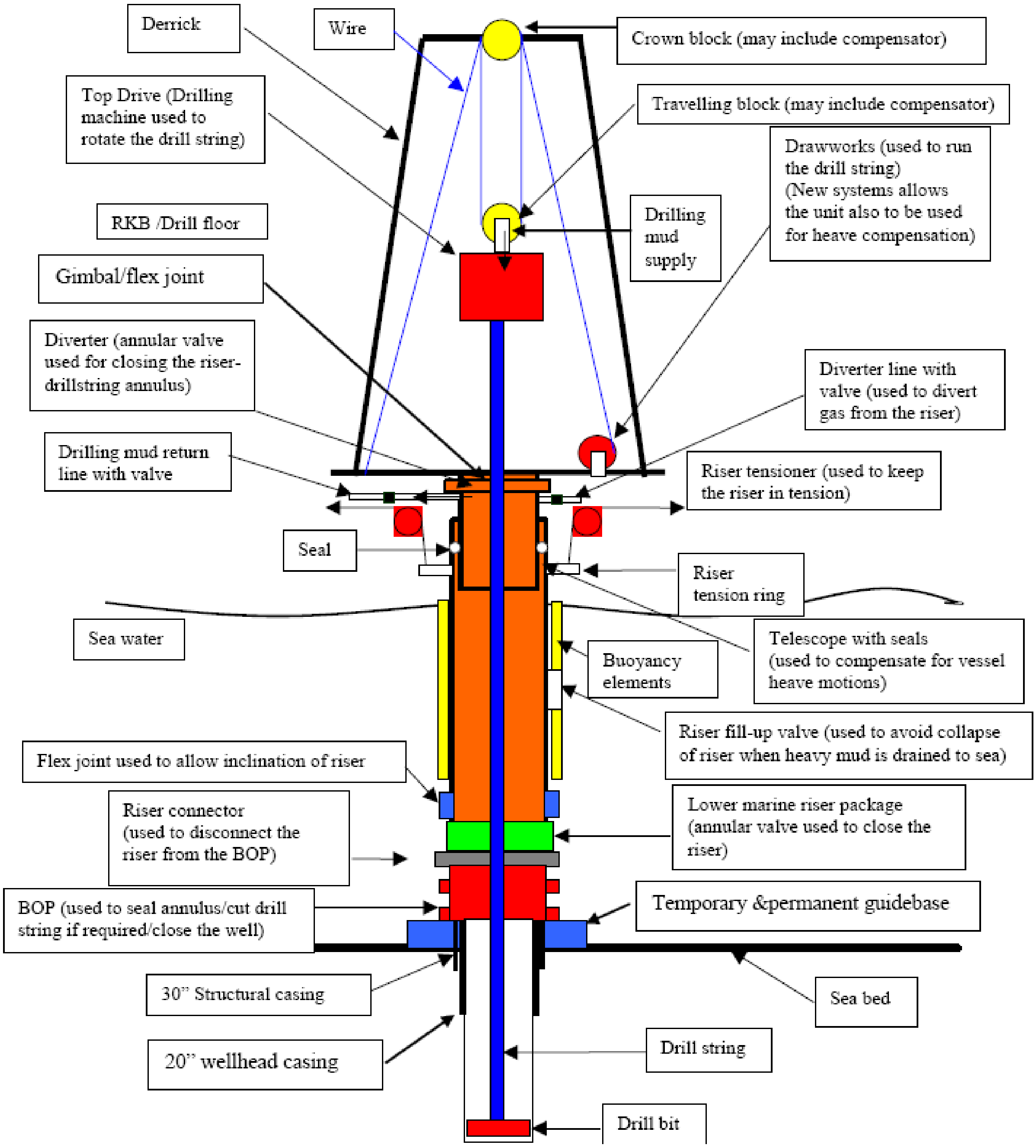



**Appendix 2: Topographic features of the marine Arctic(IASC, 2010)**

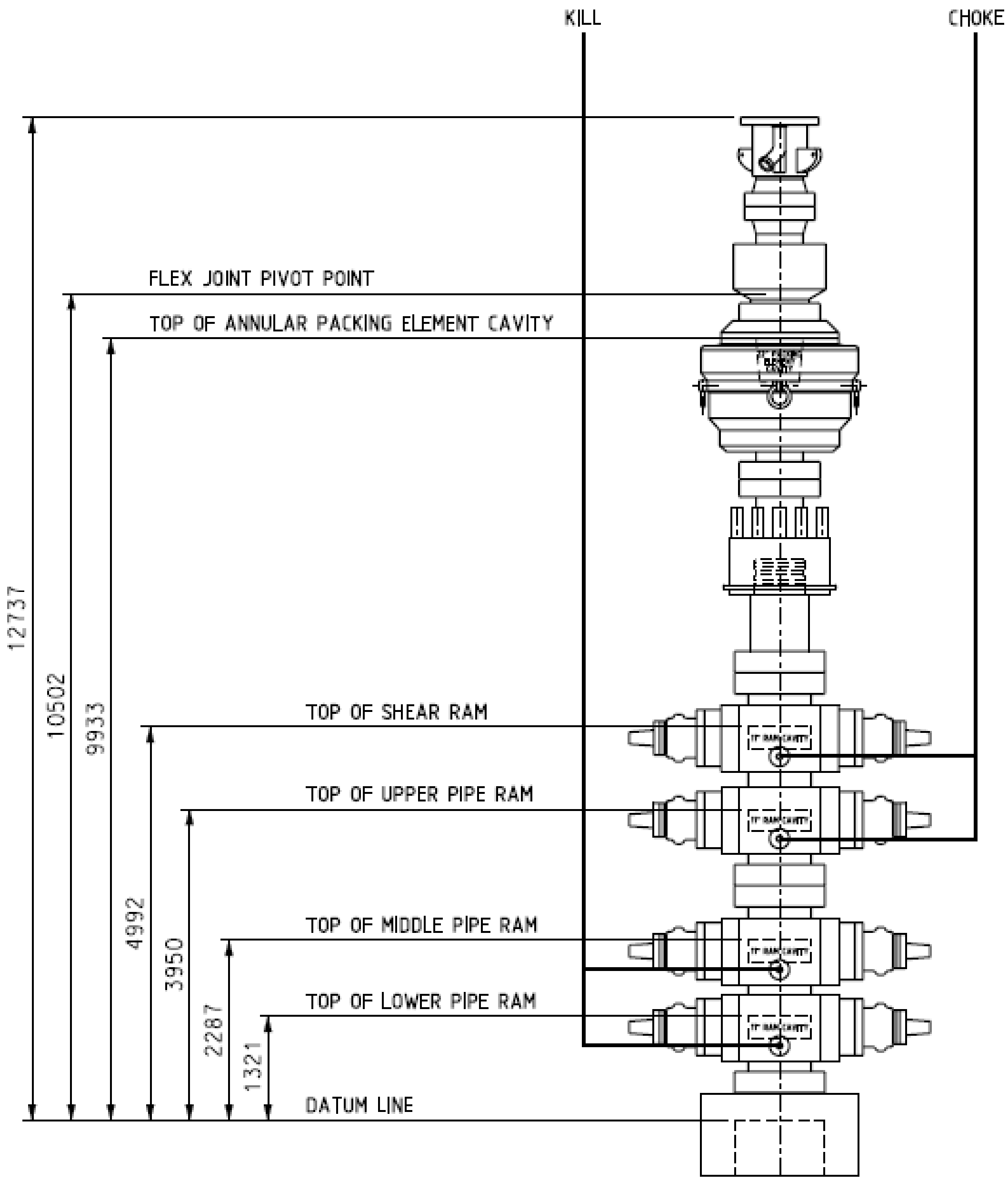



Appendix 3: Definition of the Arctic (GRID)


Appendix 4: Iceberg drift limit west of Greenland(EB, 2010)




Appendix 5: Drilling rig overview(Sangesland, 2010)




Appendix 6: BOP summary and vertical dimensions in millimetres (Transocean, 2010)

| Tasks | Activity | Considerations | *Specific hazards* |
|---|---|---|---|
| 1. 1 | **Hang off drill string in well head using EDPHOT.**<br><br>EDPHOT will be racked in derrick with a stand of DP at all times.<br><br>When evaluating the weather situation, extra time needed to pull out of hole due to possible back-reaming will be taken into account.<br><br>While drilling the 17 1/2" section, the drill string will normally not be hung off in the BOP, but pulled all the way out. | | **Procedure for Standard Hang-Off to be filled in with well-specific data, and posted on drill floor and in rig office after every casing has been set** |
| 2. 2 | Pull bit inside casing plus a distance corresponding to water depth + 2 std. | It is essential to have a correct pipe tally, and the dp stands left in derrick has to be counted to verify correct bit depth. | Wrong pipe tally can lead to bit outside casing shoe when hung off. |
| 3. 3 | Install kelly cock (in open position) with back pressure valve on top. | The tool pusher shall verify that the kelly cock is installed in string in OPEN position. | The kelly cock can be run in hole in closed position. |
| 4. | Run one std of DP in hole | | |
| 5. | Install EDPHOT w/1 std DP. Check that connections are made up. Check that back-out connections (Left hand ACME treads) are chain tong tight only. | | |
| 6. | Run hang off stand into one stand above BOP. (Space out to be able to land hang off tool without making connection in BOP). | | |
| 7. | Make up top drive to string, and Activate AHC. Run in and land EDPHOT in wear bushing/ bore protector, set down weight underneath land of point. Log weight under landing point.<br><br>Be prepared to Pick up. ____ | If much rig heaves it can be a challenge to land out gently in well head. | |
| 8. | Unscrew landing string with 15 right hand turns. | | |
| 9. | Pull out of BOP with landing string and close middle pipe-ram and b/s ram. Cont POOH w/ landing string and rack back same. | Monitor correct BOP control fluid consumption for closing rams. | **Note down string weight left in hole!** |
| 10. | Prepare and displace riser including kill, choke and booster lines to sea water. (This can be done at the same time as the drill crew trips in with the EDPHOT). | It is important to have high flow when displacing to reduce the amount of contaminated mud. | |

| Tasks | Activity | Considerations | *Specific hazards* |
|---|---|---|---|
| 11. | WOW. If weather forecast predicts possible disconnect of LMRP:. | | **See guide line # 20131: Controlled disconnect of LMRP** |
| 12. | **Retrieving drill string & EDPHOT.**<br><br>If LMRP has been disconnected and is connected back on BOP:<br><br>Pressure test choke and kill lines to decided test pressure to verify pressure control integrity. | Ensure the line up prior to pressure testing is correct. | |
| 13. | Thereafter: Line up kill line against adjustable choke, and record pressure. Open both upper and lower sub sea kill valves and observe for pressure build-up in well. Record pressure (if any). | | |
| 14. | If no pressure build-up, flow check through choke for 10 minutes.<br><br>If pressure: Bleed off in steps to zero. Monitor volume bled back. When pressure is zero: Flow check through choke for 10 minutes.<br><br>When ok: Open shear ram and flow check riser for 10 minutes. When flow check is ok: | | |
| 15. | Run in hole with DP to above BOP | | **Make sure threads matches right hand threads in the EDPHOT.** |
| 16. | Install DDM, Acticate AHC. Tag and screw into EDPHOT and torque up pipe, annular (with low pressure) can be used to centre DP if problem to enter EDPHOT. | | |
| 17. | Open middle pipe ram. | | |
| 18. | Pull EDPHOT compensated out of BOP. Continue POOH to EDPHOT is in rotary. | | |
| 19. | Service and reassemble hang-off tool after use. Rack same back in derrick ready for use. Log in drawing that treads are checked and greased. | | |
| 20. | POOH another stand to get access to kelly cock and back pressure | | |

| Tasks | Activity | Considerations | *Specific hazards* |
|---|---|---|---|
| | valve. | | |
| 21. | Close kelly cock. Slowly open back pressure valve to verify if any pressure below. Break off and remove back pressure valve. Then slowly open kelly cock to check for any pressure in string. Bleed off if some pressure. If the feeling is that it is too much pressure in string: Leave the kelly cock closed. Install DDM in string and then open the kelly cock. Thereafter the pressure in string shall be treated as a well control issue. | | |

**Appendix 7: Pipe hang off & riser disconnect procedure using EDPHOT (Lund, 2010)**

| Tasks | Activity | Considerations | Specific hazards |
|---|---|---|---|
| 1. | If time displace riser to sea water. Use upper choke outlet. | | |
| 2. | Activate AHC. | | |
| 3. | Space out tool joint to be ca. 2 m above middle pipe ram | Insure correct Space out. | If closing the ram on a tool joint, the ram can be damaged. |
| 4. | Close middle pipe ram with reduced pressure. 500 psi. | | |
| 5. | Set down 5 ton on ram, increase pressure to 3000 PSI. | | |
| 6. | Set down string weight minus the weight above the BOP. Have some over pull when cutting the string. | | |
| 7. | Cut the string using the casing shear ram. | Ensure the right ram is used. | Activate and cut with the 5K booster. |
| 8. | Pull out of BOP with the string. Close B/S ram while pulling out of riser with dp and prepare to disconnect the LMRP. | | **Ref. Procedure L4-DRL-20758** |
| 9. | Vent all functions on BOP below riser connector | | |
| 10. | De-energize stack stinger seals on both pods, leave for one (1) minute | | |
| 11. | Retract both stack stingers, leave for one (1) minute. | | |
| 12. | Energize both stack stinger seals | | |
| 13. | De-energize flow line seals, slip joint seals and diverter packer pressure | | |
| 14. | ***Riser Disconnect Execution***<br>Verify that rig is on survival draft (if time) and inform Central Control Room that LMRP will be disconnected. | | |
| 15. | Set riser tension air pressure for disconnect of LMRP, i.e. 10-15 % over pull | | |
| 16. | Disconnect by unlocking riser connector unlock. When connector is unlocked, increase riser tension by using stand-by air. Observe the LMRP lift off and ensure tensioning air pressure is high enough to prevent riser and LMRP from compensating due to sea drag. During this operation: Have one person on cellar deck to observe the equipment in moon | | |

| | | | |
|---|---|---|---|
| | pool. | | |
| 17. | Move the rig off location while slacking off on guidelines, if guide lines are connected. | | |
| 18. | When the conditions are within operational limits: Prepare the procedure for re-entering the well. | | |

**Appendix 8: Pipe hang off and shear procedure (Lund, 2010)**

| PIPE BODY | |
|---|---|
| OD of the pipe body (in) | 6"5/8 |
| ID of the pipe body (in) | 5"901 |
| Wall thickness: nominal/minimum (in) | 0"362 |
| Type of upset | IEU |
| Nominal weight (lb/ft) | 27,70 |
| Grade | S135 |
| Drift diameter/area to be drifted (in) | 4"875 |
| Collapse resistance: minimum (psi) | 7813 |
| Internal yield pressure: minimum (psi) | 12909 |
| Tensile yield: minimum (lb) | 961556 |
| Torsional yield: minimum (ft/lb) | 137330 |
| Adjusted weight (ft/lb) | 30,24 |

| TOOL-JOINT | |
|---|---|
| OD of tool-joint (in) | 8" |
| ID of tool-joint pin / box (in) | 5" |
| Tong space length: pin (in) | 10" |
| Tong space length: box (in) | 13" |
| Type of elevator shoulder: pin | 35° |
| Type of elevator shoulder: box | 18° |
| Bevel diameter (in) | 7"45/64 |
| Connexion type | 6"5/8FH |
| Tensile yield minimum (lb) | 1448416 |
| Torsional yield minimum (ft/lb) | 73661 |
| Make up torque (ft/lb) | 44196 |
| Hardbanding of tool-joint: box | Arnco 100 XT type 1 |
| Internal coating | TK 34 P |
| External rust protection | Transparent varnish |
| Type of thread storage/transport compound | Bestolife honey kote |
| Type of thread protector | Plastic |
| Effective length of drillpipe from shoulder to shoulder: tool-joint (ft) | 31,0 / 32,0 |

Appendix 9 :Drill pipe (OWS)

Fri 4/2-11

| START | END | HOURS | IADC CODE | START DEPTH | END DEPTH | ACTIVITY | MAIN / AUXILLARY |
|---|---|---|---|---|---|---|---|
| 00:00 | 01:00 | 1H0M | 5.1010 | 1400 | 1400 | Circulated hole clean with 2000 lpm - 130 bar and boosted riser with 1000 lpm. | Main |
| 01:00 | 02:00 | 1H0M | 6.3080 | 1400 | 1400 | Flow Checked for 30 min. Well static. Pmped slug. Installed two wipers in rotary. R/B drilling stand. Installed BX-elevator. | Main |
| 02:00 | 03:00 | 1H0M | 6.3012 | 1400 | 318 | POOH. | Main |
| 03:00 | 03:30 | 0H30M | 6.3080 | 318 | 318 | Flow checked for 15 min with BHA below BOP. Well static. | Main |
| 03:30 | 05:00 | 1H30M | 6.3020 | 173 | 0 | POOH with BHA. Removed wipers from rotary. L/D magnet joint, MWD teleskope, 5" HWDP single and mill assy. | Main |
| 05:00 | 06:00 | 1H0M | 6.1021 | | | M/U wash assy. | Main |
| 06:00 | 07:00 | 1H0M | 5.1010 | 38 | 142 | RIH and washed BOP with flow 2680 - 3500 lpm Spp 100 - 168 bar and 10 rpm. | Main |
| 07:00 | 08:00 | 1H0M | 6.3012 | 142 | 0 | POOH speed restricted with magnets and wash assy. Cleaned magnets. | Main |
| 08:00 | 08:30 | 0H30M | 6.3040 | 0 | 142 | Changed out jetsub to diverter sub. RIH w/wash assy speed restricted on 5" DP. | Main |
| 08:30 | 10:00 | 1H30M | 5.1010 | 124 | 327 | Flushet kill/chokelines. Washed BOP annular 2500 lpm, 18 bar and BOP rams/wellhead 3500 lpm, 38 bar. RIH 6 stands 5" DP preparing to hang off in wellhead. | Main |
| 10:00 | 11:00 | 1H0M | 6.1026 | 327 | 458 | M/U EDPHOT. Broke Acme threads and checked condition. RIH, adjusted compensator and landed out in wellhead. Sat down 9 tons keeping landing string in 5 tons tension. | Main |
| 11:00 | 11:30 | 0H30M | 6.3080 | 458 | 458 | Monitored heave and hookload. Decided to disconnet hang off tool. | Main |
| 11:30 | 12:00 | 0H30M | 6.3012 | 142 | 0 | Disconnected EDPHOT turning 7 turns to the right. POOH full bore tool speed resticted on 5" DP. Compensated string through innerbarrel. | Main |
| 12:00 | 20:30 | 8H30M | 21.1220 | | | WOW. Prepared for installing riser spider and diverter running tool. Meanwhile performed general maintenance and housekeeping. Adjusted alignment and brake out sequence on TDS. Throubleshooted on communication system between IRA/URA. Changed dies in IRN. Throubleshooted on bolts for lifting device in IRA. Secured loose bolt on TDS. Carried out PM's on rotary table. | Main |
| 20:30 | 21:00 | 0H30M | 21.1220 | | | WOW, meanwhile held pre job meeting for displacing riser to sea water | Main |
| 21:00 | 22:30 | 1H30M | 21.1220 | | | WOW, meanwhile lined up via upper Kill and Choke line and circulated and conditioned mud inside Marine Riser. Circulated with 3000 lpm, 30 Bar | Main |
| 22:30 | 00:00 | 1H30M | 21.1220 | | | WOW, emptied trip tank and displaced booster line. Lined over and pump 6m3 Premix, 6m3 HiVis pill and 6m3 wash pill train and displaced riser to sea water. Pumped with 3000 lpm, 8 bar. | Main |

Fri 4/2-11

**Appendix 10: Operational log TO winner 4/2-2011**

Operations Breakdown

Field Help Help

ONLINE OPERATIONS

| START | END | HOURS | IADC CODE | START DEPTH | END DEPTH | ACTIVITY | MAIN / AUXILLARY |
|---|---|---|---|---|---|---|---|
| 00:00 | 05:30 | 5H30M | 21.1220 | | | Waiting on Weather. Deballasted rig 2 meter. Prepared for disconnect LMRP. | Main |
| 05:30 | 07:00 | 1H30M | 21.1220 | | | Waiting on Weather. Max tension on anchor # 1: 250 ton. Disconnected LMRP from BOP @ 05:45 hrs. Moved rig 30 meters aft. | Main |
| 07:00 | 12:00 | 5H0M | 21.1220 | | | Waiting on Weather. Meanwhile performed general maintenance and housekeeping. Held thinkplan/SOP meeting and L/D diverter on rig floor. Secured diverter due to unable to L/D to deck during rough weather. Rigged up for pressure testing TDS. Deballasted rig another 2 m. | Main |
| 12:00 | 22:00 | 10H0M | 21.1220 | | | Waited on weather. Meanwhile pressure tested TDS,standpipe and surface equipment to 20/345 bar 5/10 min. Adjusted wire slings on hydraulic loop on IRA. Ballasted rig during helicopter landing to 26 m @17:00 hrs. @19:00 ballasted rig to drilling draft 24 m. | Main |
| 22:00 | 23:30 | 1H30M | 21.1220 | | | Waited on weather. Meanwhile ROV launched and installed new AX ring. Checked guide wires From BOP back to LMRP to chck all OK. Prepared cellar deck for landing LMRP. | Main |
| 23:30 | 00:00 | 0H30M | 21.1220 | | | Waited on weather. Moved rig over well centre. | Main |

Dat 5/2 - 2011

Appendix 11 :Operational log TO winner 5/2-2011

## Operations Breakdown

Field Help Help

Import IADC Save Complete

ONLINE OPERATIONS

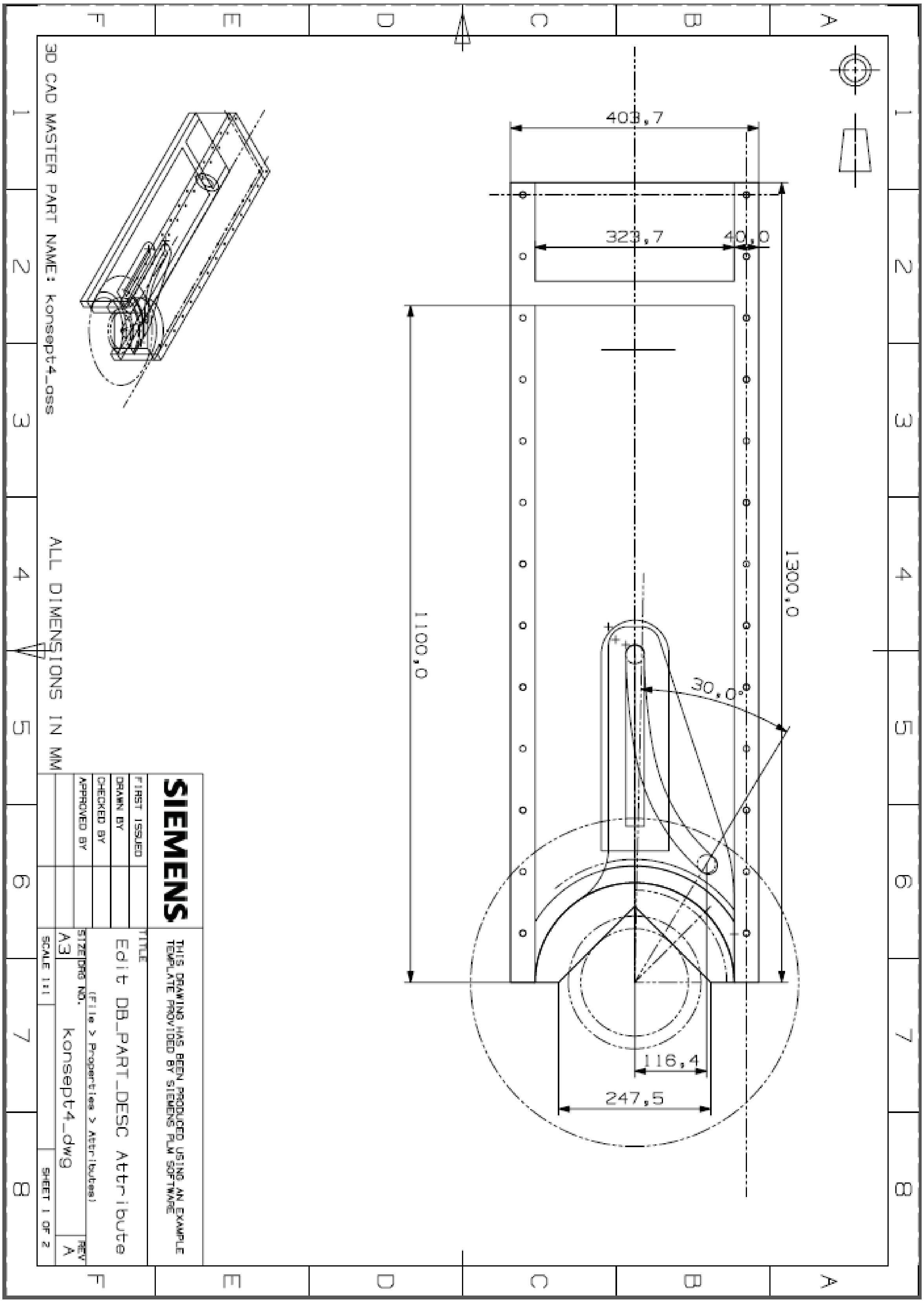
| START | END | HOURS | IADC CODE | START DEPTH | END DEPTH | ACTIVITY | MAIN / AUXILLARY |
|---|---|---|---|---|---|---|---|
| 00:00 | 00:30 | 0H30M | 21.1220 | | | Waited on weather. Landed LMRP, set down 25 tons and locked down same. Took 20 ton over pull to confirm OK. | |
| 00:30 | 01:00 | 0H30M | 21.1220 | | | Waited on weather. Installed diverter housing, locked down same and took 8 ton over pull to confirm OK. | |
| 01:00 | 01:30 | 0H30M | 21.1220 | | | Waited on weather. Rigged down diverter housing running tool. Rigged down riser spider, installed rotary table. Changed to BX-elevator. | |
| 01:30 | 02:30 | 1H0M | 19.0000 | | | Lost ID tag from lifting gear to rotary table drive ring into hole. | |
| 02:30 | 03:00 | 0H30M | 21.1220 | | | Waiting on Weather. Checked for pressure below rams. Opened MPR and BSR. Flow checked. Well static. | |
| 03:00 | 03:30 | 0H30M | 6.3032 | 327 | 469 | RIH speed restricted w/fullbore tool. Connected to EDPHOT. Installed diverter bag. | |
| 03:30 | 05:00 | 1H30M | 6.3012 | 469 | 327 | POOH speed restricted with EDPHOT. Removed diverter bag. Redressed EDPHOT and recovered ID tag on top of Grey valve. R/B EDPHOT. | |
| 05:00 | 05:30 | 0H30M | 6.1021 | | | P/U amd M/U bop test tool. Function tested bop test tool. | |
| 05:30 | 06:00 | 0H30M | 6.3032 | 327 | 469 | RIH speed restricted with bop test tool. Landed bop test tool. | |
| 06:00 | 09:30 | 3H30M | 15.1090 | | | Pressure tested BOP on yellow pod from drillers panel to 20/345 bar 5/10 min (UAP 240 bar). Functioned tested BOP on blue pod from main panel. | |
| 09:30 | 10:30 | 1H0M | 6.3012 | 469 | 145 | POOH BOP test tool speed restricted with fullboret ool. L/D test tool. POOH 6 STD 5" DP: | |
| 10:30 | 11:30 | 1H0M | 5.1030 | 145 | 145 | Held think plan/SOP meeting prior to displace riser to OBM. Displaced kill/choke and booster. Displaced riser through string 3800 L/M - 43 bar. | |
| 11:30 | 12:00 | 0H30M | 6.1022 | | | POOH 4 STD 5" DP. Cleaned magnets. | |
| 12:00 | 12:30 | 0H30M | 6.1022 | | | L/D magnets and diverted stinger. | |
| 12:30 | 13:00 | 0H30M | 6.3060 | | | Cleaned rig floor | |
| 13:00 | 18:00 | 5H0M | 7.2150 | | | Performed planned maintenance on TDS: Calibrated floor saver and anticollision system. Meanwhile function tested from control room. Drifted all 5" DP and 5" HWDP w/2 1/4" drift. | |
| 18:00 | 19:00 | 1H0M | 6.500 | | | Commenced drifting pipe in derrick. Totally drifted 78 std 5" DP and 7 std 5" HWDP including acc/jar in derrick. | |
| 19:00 | 22:00 | 3H0M | 6.1021 | | | Held Think plan meeting. P/U 8 1/2" BHA. Installed radio active sources into BHA. | |
| 22:00 | 23:00 | 1H0M | 6.3040 | 80 | 250 | RIH with 8 1/2" BHA from Derrick. | |
| 23:00 | 00:00 | 1H0M | 6.2010 | 250 | 450 | P/U and RIH with 5" DP. | |

Sum 6/2-11

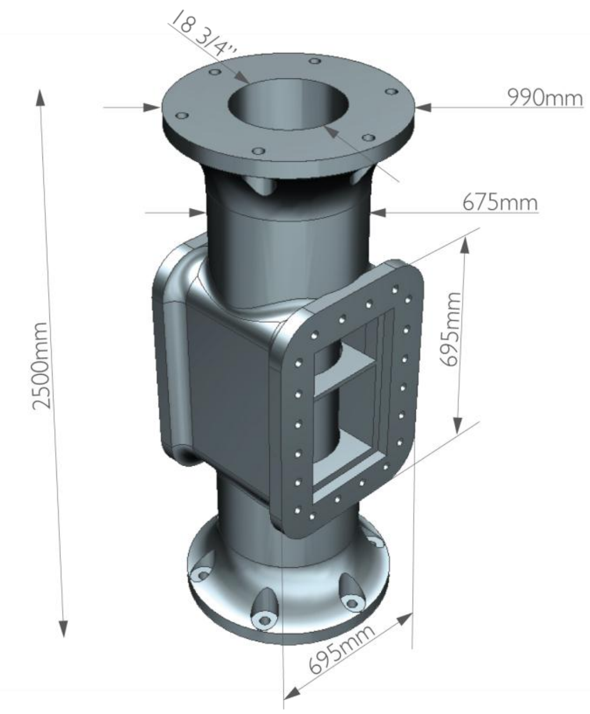
Sum 6/2-11

**Appendix 12: Operational log TO winner 6/2-2011**

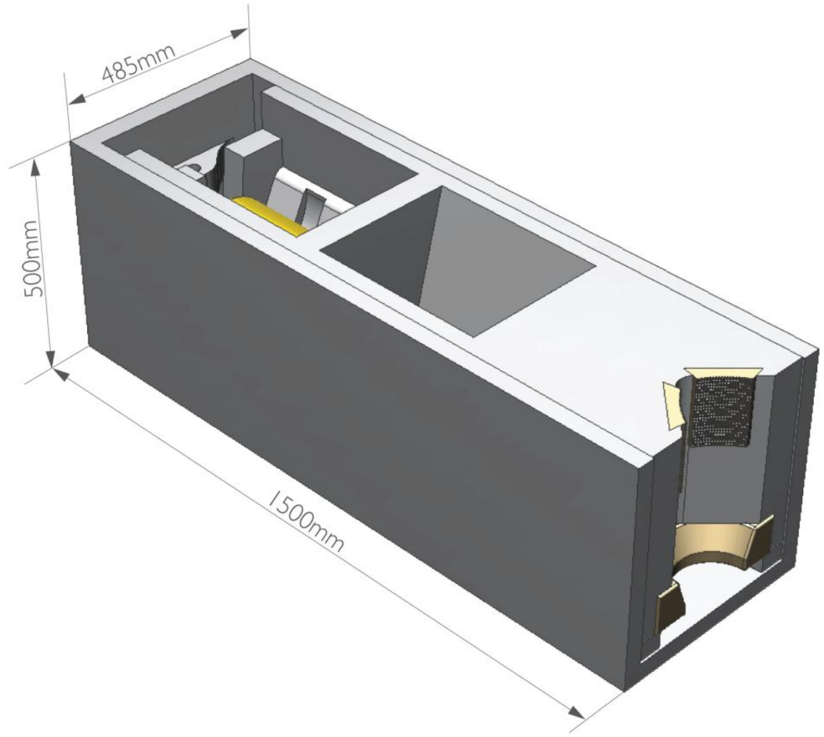
Appendix 13: SIR riser pup joint with and without machinery modules

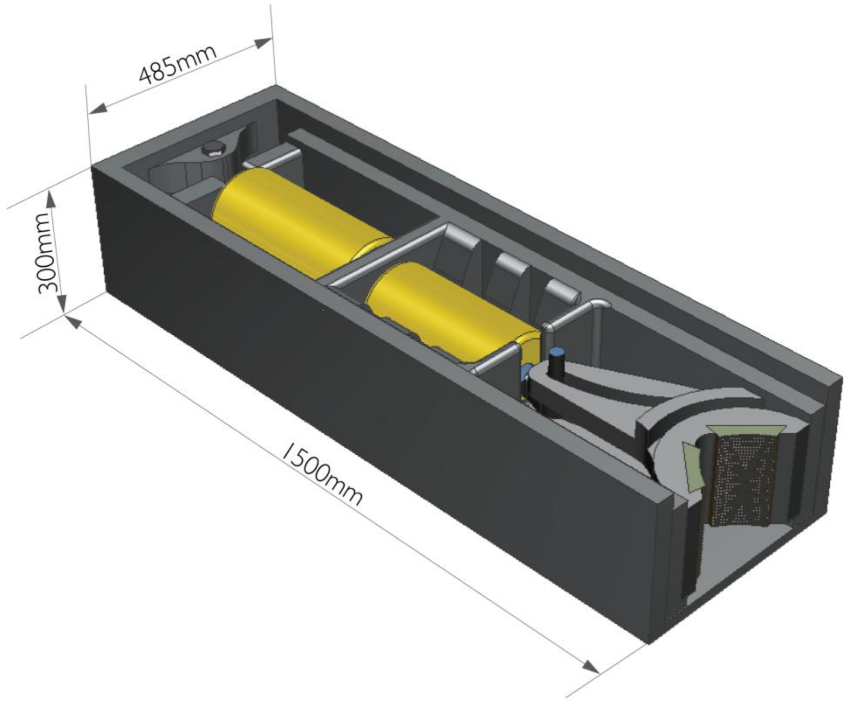



Appendix 14: Internal torque mechanism

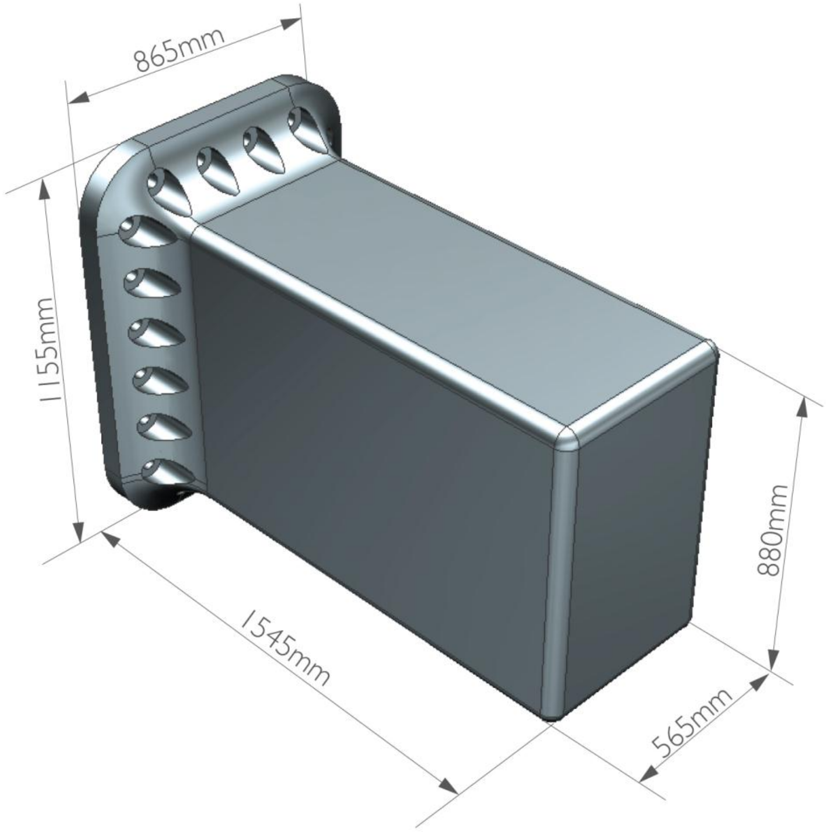




**Appendix 15: SIR conceptual dimensions**

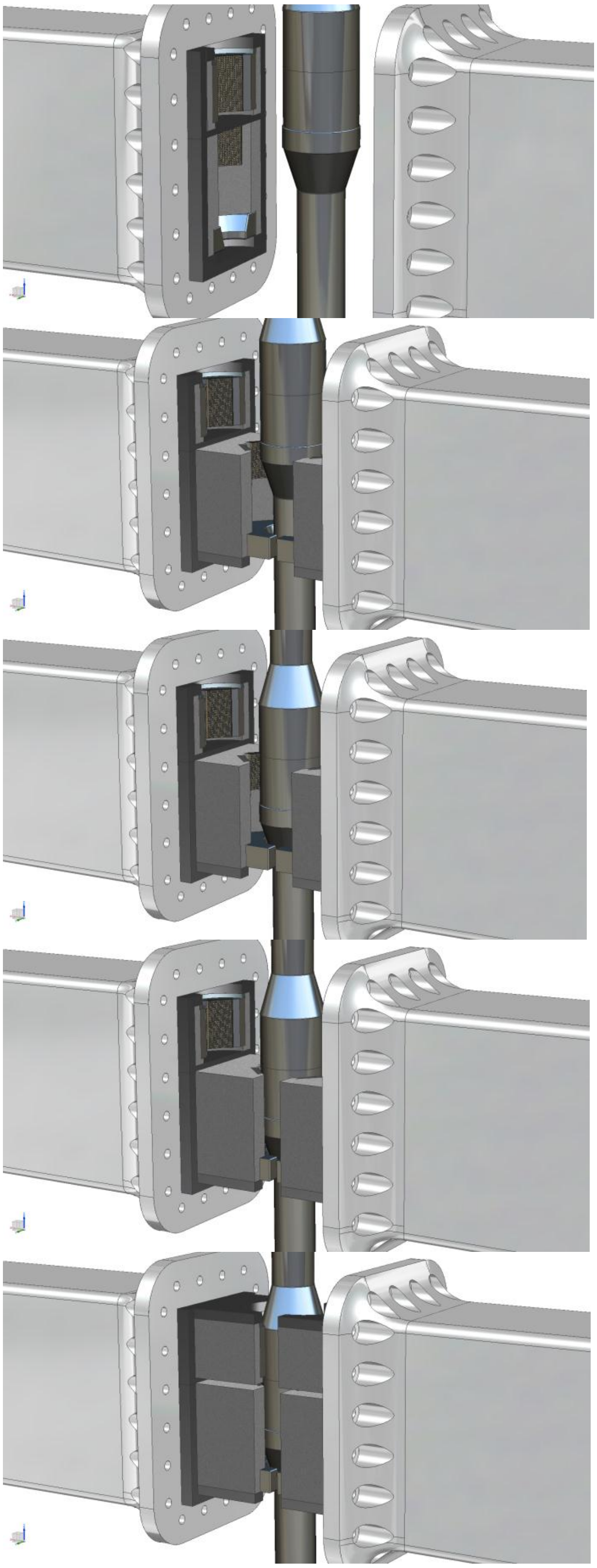



**Appendix 16: Clamp jaws conceptual dimensions**



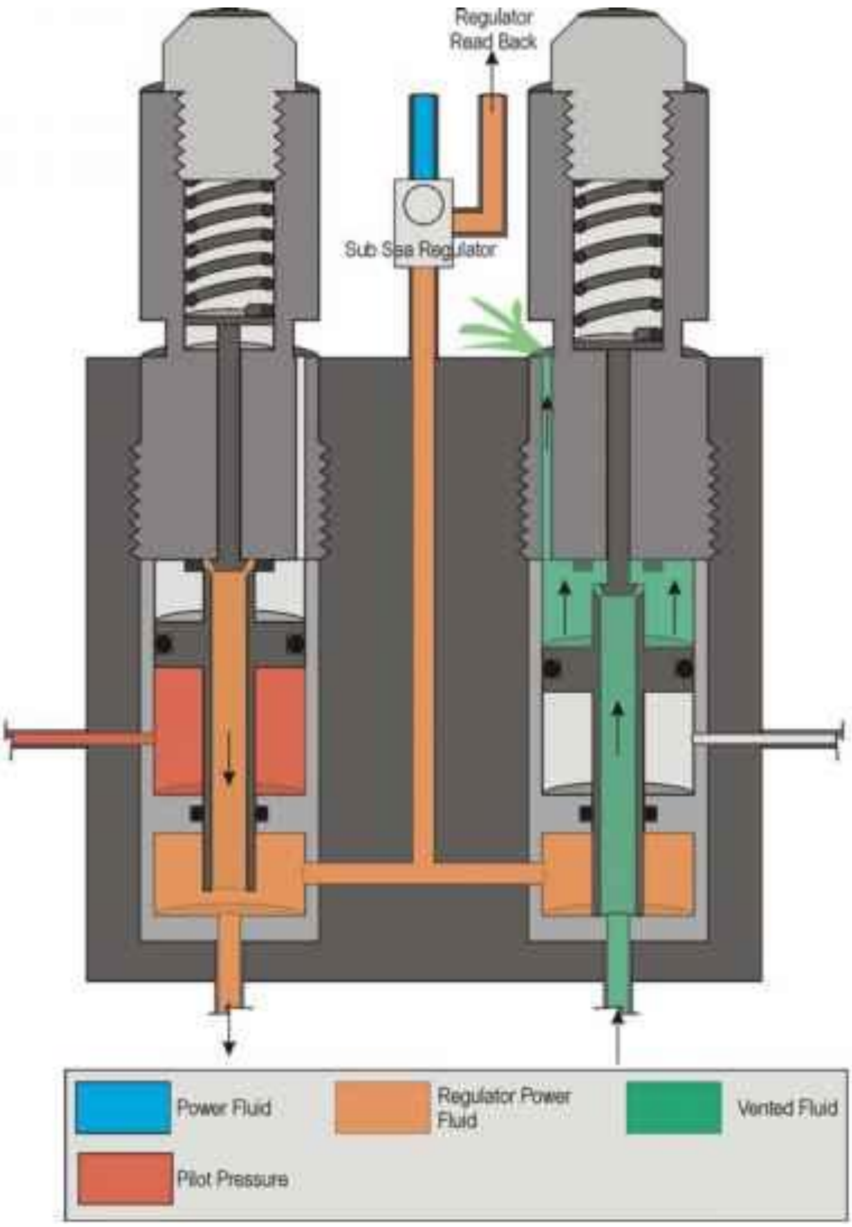

**Appendix 17: SIR machinery modules**



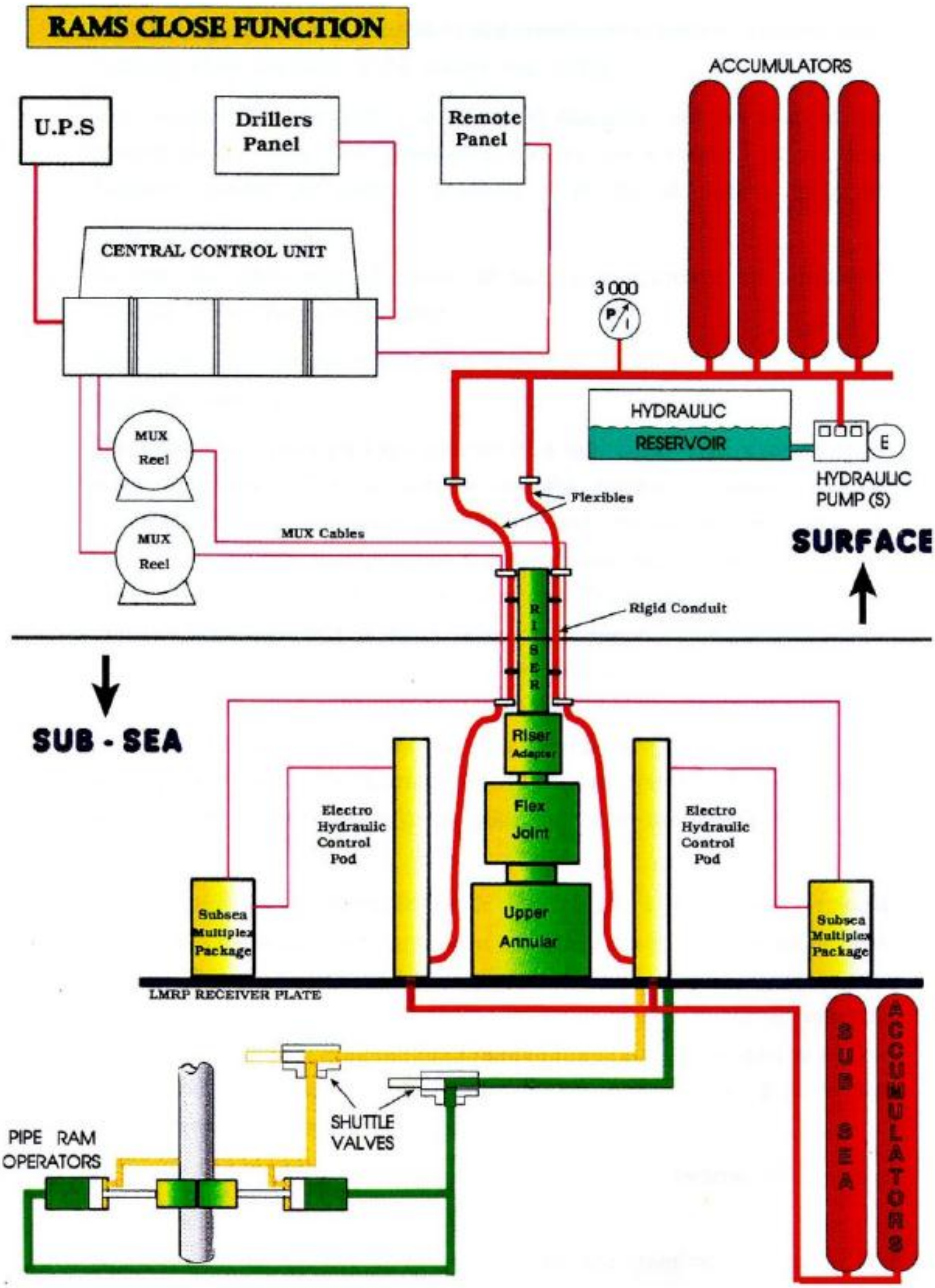
The SIR is her viewed with transparent riser pup joint

1. TJ is spaced out above SIR
2. Upper annular preventer centres the DP
3. The lower jaws are party moved into the annulus
4. The tool joint Locator is activated and engages the drill pipe tube
5. The tool joint is landed in the tool joint locator
6. Lower jaws are engaged at recommended clamp pressure
7. Upper jaws are engaged at recommended clamp pressure
8. Torque mechanism is activated applying or removing make up/brake out torque
9. 15° of rotation is accomplished
10. Upper jaw is retracted
11. Torque mechanism is reset
12. Upper jaw engages the tool joint
13. Torque mechanism is activated applying or removing make up/brake out torque
14. Point 7-12 is repeated until desired torque is achieved.
15. The jaws are retracted

**Appendix 18: The SIR's operational Visualization**




Appendix 19: principle pare of SPM valves shown on an open system, venting to sea




Appendix 20: MUX BOP control system shown closing a ram(P.Potter, 2011)

Brake out of drill pipe with SIR

| # | Inputs | Functions | Outputs |
|---|---|---|---|
| 1 | AHC is activated on the rig | | |
| 2 | Tool joint is spaced out to be above lower pipe ram using the draw work/drillers system | | |
| 3 | Signal sent from vessel to regulate pressure on lower pipe ram on SIR | | |
| 4 | | pressure regulator on lower pipe ram adjust to regulated value | |
| 5 | | | Signal is sent from SIR to surface on complete pressure regulation |
| 6 | Signal sent from vessel to activate lower pipe ram on SIR | | |
| 7 | | Lower pipe ram enters riser annulus and engages on the drill pipe diameter | |
| 8 | | | Signals are continually sent from SIR to surface on pressures, flow rates and positions of cylinders |
| 9 | DP is lowered using drillers chair/drawwork until 5 tons are set down on pipe ram using hook load cell | | |
| 10 | Signal is sent from vessel to SIR to increase regulated pressure to recommended clamp pressure | | |
| 11 | | pressure regulator on lower pipe ram adjust to recommended value | |
| 12 | | | Signal is sent from SIR to surface on complete pressure regulation |
| 13 | Signal sent from vessel to activate upper pipe ram on SIR | | |
| 14 | | Upper pipe ram enters riser annulus and engages on the pin side of the TJ. Shares pressure regulator with lower pipe ram (Flow restrictor to reduce Q?) | |
| 15 | | | Signals are continually sent from SIR to surface on pressures, flow rates and positions of cylinders |
| 16 | Signal for initiation of de-torque sequence together with de-torquepre-set value is sent to the SIR from vessel | | |

| | | | |
|---|---|---|---|
| 17 | | Torque mechanism is activated and CCW torque is applied on the TJ until mechanism reaches operational limits | |
| 18 | | | Signals are continually sent from SIR to surface on pressures, flow rates and positions of cylinders |
| 19 | | Upper pipe ram is retracted to a minimum distance from the TJ | |
| 20 | | Torque mechanism is reset to original position | |
| 21 | | Upper pipe ram engages TJ | |
| 22 | | Step 19-19 is repeated untilpre-set de-torque value is reached | |
| 23 | | | Signals are continually sent from SIR to surface on pressures, flow rates and positions of cylinders |
| 24 | | Upper pipe ram is retracted to a minimum distance from the TJ | |
| 25 | | Torque mechanism is reset to original position | |
| 26 | | | Signal is sent from SIR to vessel when de-torque sequence is completed |
| 27 | The 5 tons of hook load landed on the SIR, is picked up again using the drillers system/drawwork | | |
| 28 | Signal is sent from vessel to SIR to retract upper and lower rams | | |
| 29 | | Upper and lower pipe ram is retracted into the SIR housing | |
| 30 | | | Signals are continually sent from SIR to surface on pressures, flow rates and positions of cylinders |
| 31 | The total drillstring load is now carried by the hook and the de-torqued TJ can be slowly be landed on a dedicated BOP pipe ram located in the BOP below the SIR. | | |

**Appendix 21: control flow SIR break out**

Make up of drill pipe with SIR

| # | Inputs | Functions | Outputs |
|---|---|---|---|
| 1 | AHC is activated on the rig | | |
| 2 | Tool joint is spaced out to be above lower pipe ram using the draw work/drillers system | | |
| 3 | Signal sent from vessel to regulate pressure on lower pipe ram on SIR | | |
| 4 | | pressure regulator on lower pipe ram adjust to regulated value | |
| 5 | | | Signal is sent from SIR to surface on complete pressure regulation |
| 6 | Signal sent from vessel to activate lower pipe ram on SIR | | |
| 7 | | Lower pipe ram enters riser annulus and engages on the drill pipe diameter | |
| 8 | | | Signals are continually sent from SIR to surface on pressures, flow rates and positions of cylinders |
| 9 | DP is lowered using drillers chair/drawwork until 5 tons are set down on pipe ram using hook load cell | | |
| 10 | Signal is sent from vessel to SIR to increase regulated pressure to recommended clamp pressure | | |
| 11 | | pressure regulator on lower pipe ram adjust to recommended value | |
| 12 | | | Signal is sent from SIR to surface on complete pressure regulation |
| 13 | Signal sent from vessel to activate upper pipe ram on SIR | | |
| 14 | | Upper pipe ram enters riser annulus and engages on the pin side of the TJ. Shares pressure regulator with lower pipe ram (Flow restrictor to reduce Q?) | |
| 15 | | | Signals are continually sent from SIR to surface on pressures, flow rates and positions of cylinders |
| 16 | Signal for initiation of de-torquesequence together with de-torquepre-set value is sent to the SIR from vessel | | |
| 17 | | Torque mechanism is activated and CCW torque is applied on | |

| | | | |
|---|---|---|---|
| | | the TJ until mechanism reaches operational limits | |
| 18 | | | Signals are continually sent from SIR to surface on pressures, flow rates and positions of cylinders |
| 19 | | Upper pipe ram is retracted to a minimum distance from the TJ | |
| 20 | | Torque mechanism is reset to original position | |
| 21 | | Upper pipe ram engages TJ | |
| 22 | | Step 19-19 is repeated untilpre-set de-torque value is reached | |
| 23 | | | Signals are continually sent from SIR to surface on pressures, flow rates and positions of cylinders |
| 24 | | Upper pipe ram is retracted to a minimum distance from the TJ | |
| 25 | | Torque mechanism is reset to original position | |
| 26 | | | Signal is sent from SIR to vessel when de-torquesequence is completed |
| 27 | The 5 tons of hook load landed on the SIR, is picked up again using the drillers system/drawwork | | |
| 28 | Signal is sent from vessel to SIR to retract upper and lower rams | | |
| 29 | | Upper and lower pipe ram is retracted into the SIR housing | |
| 30 | | | Signals are continually sent from SIR to surface on pressures, flow rates and positions of cylinders |
| 31 | The total drillstring load is now carried by the hook and the de-torqued TJ can be slowly be landed on a dedicated BOP pipe ram located in the BOP below the SIR. | | |

**Appendix 22: control flow SIR make up**

The following appendix contains the Preliminary Hazard Analysis of the control proposals.
The analysis is divided into systems that when combined, make up the different control system.
Each entry has an accompanying reference number (ref #) each belonging to a number series indicating which sub system the entry is a part of.

The list of number series are:

| Number series | Deals with |
|---|---|
| **100-…** | General hydraulic control/layout |
| **200-…** | hydraulic, control and electric power from existing MUX system |
| **300-…** | subsea battery bank |
| **400-…** | Subsea HPU |
| **500-…** | Acoustic communication |
| **600-…** | Dedicated umbilical from vessel to SIR |
| **700-…** | Recharge of energy subsea with the use of ROV |
| **800-…** | Only power and control from BOP MUX system |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk Freq. | Risk Consequence | Risk RIN | corrective measures | comment |
|---|---|---|---|---|---|---|---|---|---|
| **Operation panel** | Human Error | 101 | If operated with one hand intervention, the wrong button can be pushed | Activation of user/ sequence at a the wrong time | 3 | 1 | **4** | 2 handed operation to be implemented in the design of master panel | |
| **Hydraulic fluid** | Spill | 102 | Burst of pipe, fitting, seal etc. | environmental contamination | 2 | 2 | **4** | Use water based hydraulic fluid if conventional oil based fluids prove difficult to utilise | |
| **Hydraulic fluid** | contamination | 103 | Bacteria cultures can develop in the fluid | Operational deviation, clogging of pipes, degraded components and censors. | 1 | 2 | **3** | Fluid additives can be used to minimize this hazard. Optical sensors can be used to identify fluid condition and show trends | |
| **Hydraulic fluid** | contamination | 104 | If oil based hydraulic fluid is used, water ingress in fluid due to leaks from sea or riser annulus, can happen. | Corrosion, particles and operational reliability degradation. Possible retrieval of equipment for corrective maintenance. Damage to internal components | 2 | 2 | **4** | Implement sensors for measurement of water in fluid. ROV fluid test retrieval | Only if oil based hydraulic fluid is used |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Freq. | Consequence | RIN | | |
| **Hydraulic fluid** | contamination | 105 | Additive levels change over time due to water ingress, leaks, setteling etc | Loss of fluid properties, corrosion, bacterial growth, operational reliability degradation | 4 | 1 | **5** | Implement sensors for fluid properties monitoring or ROV fluid test retrieval | Independent of oil based or water based hydraulic fluid is used |
| **Hydraulic fluid** | Thermal energy | 106 | Temperature increase in fluid due to Internal leaks originating in seal/component wear, incorrect operations in relief valves/pressure reducing valves, or to high fluid viscosity | Viscosity changes, loss of fluid properties/additives. Increased wear and tear on components, leaks to environment, increased maintenance cost | 5 | 2 | **7** | Temperature sensors to log historical data, trend viewing can give good indication of system condition and help in planning of preventive maintenance. | |
| **Hydraulic fluid** | pressure | 107 | Component being moved by hydraulic actuator experience larger forces due to fluty mating surfaces or other component fault. | Pressure will rise when moving the component as it will require more work to do the same job. Will lead to component failure in the end | 5 | 1 | **6** | Pressure sensors to log operations and have set values for normal and degraded operation. This might give good indication of component condition and help in planning of preventive maintenance. | |
| **All components** | timing | 108 | Developing fault in cylinder seals or component being moved by actuator. | Time for activation to completion of a process increases | 5 | 1 | 6 | Sequences should be timed and logged. This might give good indication of component condition and help in planning of preventive maintenance. | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Freq. | Consequence | RIN | | |
| **All components** | Hydraulic pressure | 111 | Pressure peak above design pressure | Burst of pipe, pipe bend, fittings, flexible hose with subsequent environmental contamination | 5 | 2 | **7** | Design in pressure relief valve with return to reservoir | **ALARP** |
| **Lower Clamp Cylinder (LCC)** | Movement | 112 | The upper clamp Cylinder (UCC) shares pressure regulator with the LCC, but the design of the clamps differ. | No relative rotational movement between the box and pin end of TJ when detorquing . One of the clamps might slip on the TJ tong space. Loss of operational effectiveness and possible shear of DP | 5 | 3 | **8** | Use separate pressure regulator on U/LCC | **Not acceptable RIN #** must be re-designed |
| **Clamp Cylinders** | Hydraulic pressure | 113 | Too much clamp force is applied | Higher break out torque is required to achieve relative rotation. might not be able to brake. " False" torque can be experienced when making up a TJ connection. Unsecure connection when returning to operation | 5 | 2 | **7** | Pressure feedback loop must give read back pressure, mounted after user pressure regulator. | **ALARP** Already taken into design |
| **De-torque** | Direction | 114 | Faulty Directional Control valve (DCV) setup or operation | Torque is applied in the wrong direction, widening of operational window, possible shear of DP | 2 | 2 | **4** | Position indicator on cylinder, feeds SCM with changes. Corrections can be made. Carry out commissioning tests of full operation upon installation in stack. | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Freq. | Consequence | RIN | | |
| **Hydraulic fluid venting** | Hydraulic pressure | 115 | Clogging or other hydraulic resistance in return line to reservoir | The vented hydraulic fluid will propagate in the system and pressurize other users pistons. Movement of unplanned components | 5 | 2 | **7** | Implement check valves to isolate the users on the vent line. | **ALARP**<br>Already in design |
| **Locating DP TJ** | timing | 116 | Hydraulic losses, friction and time to build up required pressure might create a time lag to position the LCC in the riser bore | TJ might be lowered before LCC is in right position. Lost operational time. | 5 | 1 | **6** | High volumetric flows must be available subsea, accumulator bank or high effect HPU can deliver this Q at the right pressure. Position signals on clamp cylinders to inform operator and SCS | Small bank of accumulator is shown in generic hydraulic layout drawing |
| **Accumulator bank** | Hydraulic pressure | 117 | Pressure builds up when stack is retrieved to the surface. | Burst of accumulator bottles, pipes or fittings with environmental spills as a result | 5 | 3 | **8** | implement accumulator dump valves with return to reservoir | Not acceptable RIN#<br>Already in design |
| **Active heave compensator** | Forces | 118 | Failure in AHC while clamp cylinders are engaged on TJ | Large vertical forces. Damage to SIR, flex joint, reduction of riser integrity, well control issues | 2 | 3 | **5** | Load censors can initiate a automatic retract of the clamp cylinders and provide the user with info on how large the forces are at any time. | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Freq. | Consequence | RIN | | |
| **Torque Pressure regulator** | Hydraulic pressure | 119 | Failure to regulate to correct pressure | Wrong torque is obtained. Failure to reach the design intent. | 5 | 2 | **7** | Pressure sensor mounted after pressure regulator in hydraulic design for verification of correct pressure | Already implemented |
| **Clamp cylinder** | Speed | 120 | DCV feeds a higher Q then required, to high gain in controller | High engagement speed, impact with TJ, damages to dices as they are hard and brittle. Loose objects in wellbore with the potential of damage to drilling and well control equipment | 4 | 2 | **6** | Flowmeter/position transmitter can be used to derive the engagement speed and correct the DCV feed. | |
| **LCC** | Forces | 121 | Load cell on drillers equipment is faulty when landing the 5 tons of hook load to locate the correct TJ | Large vertical forces. Damage to SIR, flex joint, reduction of riser integrity, well control issues | 2 | 3 | 5 | Load censors can initiate a automatic retract of the clamp cylinders and provide the user with info on how large the forces are at any time. | |
| **Vertical load cell on clamp cylinders** | Error | 122 | Load sensors send out signal of large forces, in a situation where this is not correct. | Initiation of automatic retract of the cylinders, loss of operational efficiency. Possible shearing of DP | 2 | 2 | **4** | 2 or more sensors can work in a system where a majority desertion can be made. Thereby eliminating a faulty sensor | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Freq. | Consequence | RIN | | |
| **UCC** | Size of components | 123 | Upper pipe clamp cylinder will not engage due to friction, jam created by contamination | Operation cannot be completed | 2 | 2 | **4** | Pressure sensors, in relations with position indicators can build up historical trends and thereby giving us the posebility to se trends in the cylinder friction. Flush ports might be consider | |
| **UCC** | speed | 124 | UCC DCV feeds to large volumetric flow | High engagement speed, impact with TJ, damages to dices as they are hard and brittle. Loose objects in wellbore with the potential of damage to drilling and well control equipment | 4 | 2 | **6** | Flowmeter/position transmitter can be used to derive the engagement speed and correct the DCV feed. | Same as ref #:120 |
| **De-torque** | Forces | 125 | Too much torque is removed from the TJ connection | Potential for dropping the lower part of the DP(BHA) in wellbore when picking up the DP and running it down in the BOP for hang off. | 3 | 4 | **7** | A safe de-torquevalue must be deduced and a accurate method of measuring it must be designed | |
| **De-torque** | Forces | 126 | To little torque is removed from the TJ connection | DDM cannot spin out the hanged of tool joint in the BOP. Repeat of de-torque sequence, increased time. | 4 | 2 | **6** | A safe de-torque value must be deduced and a accurate method of measuring it must be designed | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **De-torque** | Forces | 127 | BOP pipe ram cannot fixate the "safe torque" value mentioned in #225-126 | No spin out is achieved in BOP | 3 | 2 | 5 | Data must be gathered from suppliers of pipe rams/experiments must be done to get empirical data. This must taken into the consideration when addressing the "safe de-torque value" | |
| **De-torque** | Forces | 128 | Large contact faces in de-torque mechanism, might create very large frictional forces. | Incorrect torque values are registered by control system/operator | 5 | 1 | 6 | Ref to number 125-126 | |
| **UCC** | position | 129 | The UCC is to close to the TJ surface when resetting the torque mechanism. | Dice damages, TJ damage, debris in wellbore. Damages on drilling/well control equipment | 5 | 2 | 7 | Position indicator on clamp cylinders to verify position. | |
| **De torque** | Position | 130 | No relative rotation of pin in relations to box end of TJ. Due to slipping dice on tong space | No torque is removed from connection, | 3 | 3 | 6 | A method to accurately monitor relative rotation of TJ can be found and implemented in the design. Possible that monitoring of torque-turn can give a good decision basis. | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **LCC** | Position | 131 | Relative position difference when entering riser annulus | May experience challenges related to centering of DP | 5 | 1 | **6** | Position indicators on LCC can feed control system and synchronize positions. | |
| **LCS** | Locating | 132 | TJ not centered in grip segment | Not sufficient contact surface between TJ and dices. No torque can be transmitted | 5 | 2 | **7** | Redesign of LCS to assist in centering of DP. Look at utilizing upper annular preventer in this operation. | |
| **Clamp Cylinders** | Position | 133 | U/LCC will not retract into SIR | Restrictions present in riser bore. Operations over the cross section of the SIR are to some degree halted | 2 | 2 | **4** | Fail safe DCV design which allows for pressure on retract side of hydraulic actuator, and venting of the other side. Possible with mechanical ROV override design. | |
| **Picking up the DP after being fixated in the SIR** | Dropped object | 134 | Spin out of threaded connection in TJ due to little effect or residual torsional forces in drill string | When LCC is retracted, the DP can be dropped in the wellbore | 2 | 3 | **5** | Load cells on LCC.<br>Introduce mandatory pick up test(overpull) when still clamped, to verify that there is a connection between pin and box end of TJ. Carry out CW turn with DDM to specified torque to verify that there is a fixed connection in threads. | Procedure and training, instrumentation |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Human error** | Information flow | 135 | Operator aims at wrong de/torque value | To little/much torque is applied to the TJ in question. Damages to treaded connection, dropped drill pipe if torque is low | 3 | 2 | **5** | Automatic verification of input data, DP size, torque etc. by SIR control system. Procedures for verification of input values of second person | |
| **Human error** | Direction | 136 | Operator maces wrong decision and initiates wrong direction on hydraulic user | Increased operational time, loss of energy capacity subsea. Loss of fixated and located TJ. | 5 | 1 | 6 | Built in sequences in SIR for automatic stepwise operation | |
| **Automatic sequence** | Faulty operation/components | 137 | Errors are spotted in feedback information, by human operator. Or operational consideration demands another task to be prioritized. | Faulty operational result, redo operation | 5 | 1 | 6 | Operator must be able to safely abort/intervene in automatic sequence. The SIR must also be able to be remote operated one and one order in case of unforeseen circumstances. | |
| **Automatic sequence** | Operational control | 138 | Operator is not getting the feedback data in the required pace | A faulty operation Is carried out subsea, must be redone and creates additional time use. | 5 | 1 | 6 | Operational speed and data amount sent, must be adapted to the bandwidth limitation in the system | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Clamp Cylinders** | Position | 139 | Clamp cylinder is in riser annulus when all hydraulic pressure is lost | No energy is available to retract the clamp cylinders. | 2 | 2 | **4** | ROV mechanical override can be considered. | |
| **All components** | impurities | 140 | Cuttings, mud additives, sealing fragments etc | Clogged/jammed components, no operational goals can be achieved. Shearing of DP | 5 | 2 | 7 | Appropriate seals shoud be used, with over pressure in SIR so that the leak path is given. From SIR to riser annulus. The losses can be monitored and show trends in leaks, this might assist in maintenance planning | |
| **All components** | Pressure | 141 | Moving actuators and components in a confined fluid filled cavity. | Creates pressure and under pressure if the fluid cannot escape or be replaced . Nothing will work or burst of seal to environment, something will give. | 5 | 3 | 8 | Reservoir can be integrated with the cavities in the SIR. All parts of the must have appropriate conduits for venting and replacement of volumes to and from confined cavities. | **Not acceptable RIN Must be correct in design** |
| **Seal against riser annulus** | pressure | 142 | The hydrostatic pressure as a result of high specific gravity drilling mud is much higher than the ambient pressure as a result of seawater pressure on the SIR. | Pressure in riser is higher than in SIR. leak path is opposite than design intension. Influx of impurities in SIR | 5 | 2 | 7 | Pressure sensor in riser annulus can feed info on riser annulus pressure. The cavities in the SIR can then be pressurized to correct level (equal or higher). This must be mapped with a pressure sensor.The consequence of this must be mapped and understood | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Pressure sensor** | failure | 143 | Pressure sensor in riser annulus or SIR as mentioned in #142 is faulty | The SIR is pressurized to a incorrect pressure, higher or below design intent. Leak of fluid | 1 | 2 | **3** | 2 or more sensor can be used in both cases. A democratic decision can then be made and a faulty sensor can be switched of. | |
| **Piping** | Leaks | 144 | Fittings on external pipe leaks | Environmental contamination | 3 | 1 | **4** | Use a minimum of external fittings. Look for the correct quality in fittings under the acquisition process. | |
| **Power deliverance** | Electrocution | 145 | Electric components sends current in the metal parts of the SIR | Electric shock can be given to humans operation or handling the equipment | 3 | 1 | **4** | Good electric engineering practice should be applied under the design of the electrical components | |
| **Maintenance** | Hydraulic pressure | 144 | Residual hydraulic pressure is still in components when handled by maintenance | Harm to humans and assets | 2 | 2 | **4** | Bleed of possibilities /tools to be used | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Hydraulic Fluid** | Air buble | 145 | Pumps, valves and sudden cross sectional changes can crease air bubbles | Dramatic reduction in bulk modulus for the system. This may lead, depending on the extent of air in fluid, to the so-called spring effect in the hydraulic pressure on end users | 5 | 1 | **6** | This must be considered in design of the hydraulic system and the reservoir design. | Practical tests must be carried out on the final design |
| **Torque mechanism** | Position | 146 | operated beyond its design rotational limitations | Forces are distributed on faces that are not intended to withstand these forces | 5 | 1 | 6 | Limit switches are implemented with the use of position data to ensure that cylinders are not pushed beyond operational limitations | |
| **All hydraulic cylinders** | Position | 147 | operated to the utmost physical cylinder limitations | The available hydraulic areal is lost as the piston surface is in contact with the wall. The pressure can therefore not work on the complete piston areal. The cylinder cannot start to move | 4 | 2 | 6 | Limit switches are implemented with the use of position data to ensure that cylinders are not bottomed out | This must be implemented in design |
| **Hydraulic fluid** | Temperature | 148 | Low temperature might create freezing situation | Blockade of conduit | 3 | 4 | 7 | Use fluid additives to lower freezing temperature | Normal practice on NCS |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Rigid pipe between hydraulic control unit and flex joint** | Burst | 201 | Burst due to pressure above design intent in additional pipe leading up to the SIR from control location | Environmental contamination, loss of hydraulic power in BOP control system, well control issues | 2 | 5 | **7** | Pressure relief valves, safety factors used in design process. | Not acceptable end result. Fail safe valve is in design |
| **Hydraulic fittings on hydraulic line between BOP system and SIR** | Leak | 202 | Leak from fittings due to errors in mounting, and degrading over time | Environmental spill, loss of hydraulic power in BOP control system. Well control issues. | 1 | 4 | **5** | Pressure testing upon commissioning and routinely when accessible on surface | |
| **Flexible hydraulic conduit from LMRP across lower flex joint to SIR** | burst | 203 | Fatigue, cracking or any leak in flexible hydraulic hose | Environmental spill, loss of hydraulic power in BOP control system. Well control issues. | 1 | 4 | **5** | Work closely with supplier of components, visual and NDT testing. Routinely change out to new components. Check valve to be installed between SIR acc. Bank and flexible conduit. | |
| **Flexible hydraulic conduit from LMRP across lower flex joint to SIR** | Leak | 204 | Wear due to angular movement degrades component | Environmental spill, loss of hydraulic power in BOP control system. Well control issues. | 3 | 4 | **7** | Securing to ensure room for movement, Work closely with supplier of components, visual and NDT testing. Routinely change out to new components .Check valve to be installed between SIR acc. Bank and flexible conduit. | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **SIR** | Contamination | 205 | Debris from components in SIR is carried with the hydraulic fluid to the subsea central BOP control unit | SPM valve contamination. Leaks over seal surfaces, pulling of entire BOP to clean. | 5 | 3 | **8** | Separate hydraulic system on the SIR and the BOP. Increase fluid condition surveillance and filtering | **NOT acceptable RIN** |
| **Electrical cables from control pod on LMRP to SIR subsea control module** | Electric energy | 206 | Cable wear due to angular movement degrades isolation | Short-circuit of cable | 2 | 2 | **4** | Fuse in MUX control pod to ensure that the error does not propagate to BOP control system | |
| **SIR SCM** | Electric energy | 207 | Malfunction in electric/tonic components leads to short circuit | Loss of control of SIR, possible effect on BOP control system, well control issues | 1 | 5 | **6** | Fuse in SIR SCM/BOP control pod. All mitigating measures must be used to reduce the effects on BOP control system | |
| **Electric connectors** | Electric energy | 208 | Leak in connector seal | short circuit, loss of control of SIR, possible effect on BOP control system, well control issues | 1 | 5 | **6** | Fuse in BOP control pod. all mitigating measures must be used to reduce the effects on BOP control system | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **BOP control pos** | Electric energy | 209 | Additional components in control pods increases chance of error | May create operational deviations in BOP control pod, loss of one control pod | 3 | 2 | **5** | Keep additional components in BOP control pod to a minimum | |
| **BOP control pos** | Electric energy | 210 | Additional components in control pods increases chance of error | May create operational deviations in BOP control pod, loss of both control pod | 1 | 5 | **6** | Keep additional components in BOP control pod to a minimum, only use the additional components on one of the control pods. | |
| **Operator** | Human error | 211 | If operated on the BOP master panel, a wrongful order can be sent to the BOP | BOP function activated with wrong operational timing, time loss | 1 | 1 | 2 | Use separate control panel for SIR | |
| **Additional hydraulic users** | Hydraulic pressure | 212 | Introducing new hydraulic user on the BOP control system | Not enough accumulator usable hydraulic volume , well control issues | 1 | 5 | 6 | Install additional subsea accumulators | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Accumulators** | forces | 213 | Ref # 212, increasing accumulator bang size | Added weight, more loads on the riser tension system, more forces on bop stack, wellhead. | 5 | 2 | **7** | Look for other control option that does not include resizing of accumulator bank. Use light weight composite accumulators. Use helium as pressure gas instead of nitrogen. | |
| **Communication** | Congestion | 214 | All the sensors, data logs and real-time info is transferred over the same info carrier as the BOP control signals | Bandwidth can be exceeded on the information carrier | 1 | 5 | 6 | Priority should be given to BOP control system information, safety critical info. Hierarchy system must be implemented | |
| **Topside components** | Component fault | 215 | The BOP control topside equipment will have additional components in connection with the introduction with the SHFW | Component fault propagates in the system with the effect of reduced operational possibility of the MUX control system | 1 | 4 | **5** | Design so that faults in the additional system does not affect any other parts of the BOP control system | Has been done historically with the use and control of cameras, additional sensors. Ref API 16 D, section 5.6.5 |
| **LMRP Accumulators** | Leak | 216 | Hydraulic leak between LMRP and SIR | Loss of hydraulic pressure on LMRP | 2 | 4 | **6** | Section the accumulator bank, resize with bigger safety margin so that LMRP will have the desired hydraulic capacities in all situations | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Battery** | Capacity | 301 | Low temperatures reduces the battery capacity | Not enough available energy to complete sequence | 5 | 2 | **7** | Use batteries that are designed for the required temperature range, safety margin in designing battery package | Must be taken into design |
| **Battery** | Capacity | 302 | If discharged quickly, the battery cannot deliver the same effect as if discharged slowly | Not enough available energy to complete sequence | 5 | 2 | **7** | Use batteries designed for a high ampere output.<br>safety margin in designing battery package | Must be taken into design |
| **Battery** | Capacity | 303 | If numerous discharges are performed, capacity might change | Not enough available energy to complete sequence | 3 | 2 | **5** | Use batteries design for multiple run downs, instrument the batteries with mentoring of voltage and power output to create historical trends. might assist in maintenance planning | |
| **Battery** | chemicals | 304 | Rigging and maintenance of battery pack might expose personnel for chemicals | Environmental spills, harm to paersonell | 3 | 2 | **5** | Include personal protective equipment (PPE) , adequate procedures and training of personnel | |

| System activity/eleme nt | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Battery** | Electric shock | 305 | Creep current from faulty connection and/or components | Not enough available energy to complete sequence | 3 | 3 | **6** | Instrumentation of battery pack, current must be logged | |
| **Battery** | Capacity | 306 | Chemical deterioration of battery | Timely deterioration of available energy subsea, not enough energy to complete operation | 1 | 2 | **3** | Continues or routinely charging of battery pack is needed, monitoring of trends will help in maintenance planning | |
| **Battery** | spill | 307 | Battery might leak chemicals to environment | Environmental spill | 1 | 1 | **2** | Possible to encapsulate the battery | |
| **Battery maintenance** | Dropped object | 308 | When handling a large number of single batteries, there is a increased risk for dropped objects under lifting operations | Human, asset harm, spill and loss of operational time | 4 | 2 | **6** | Desisg battery module with suitable lifting ears/ appliances. | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Battery** | Pressure | 309 | Sea water pressure on battery | Loss of containment, spill, loss of energy subsea | 5 | 2 | **7** | Use batteries design to withstand pressure or enclose battery modules | |
| **Batery** | Forces | 310 | The additional weight of the battery package | Must be compensated by riser tension system, increased loads on bop stack, FJ and well head. | 5 | 1 | **6** | Limit weight in design | |
| **Battery** | Electrical energy | 311 | Chemical reaction when charging batteries. This will produce waste products , like gas | If gas is a west product, pressure buildup might arise. | 2 | 2 | **4** | Relief valve to be used on batteries if gas is present while charging. | |
| **Battery** | Thermal energy | 312 | large amounts of energy is being withdrawn from the battery in a short time period | Thermal energy build up in battery | 2 | 1 | **3** | Increase battery module surface area if this proves to be a problem in tests. | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Battery** | Chemicals | 313 | Chemicals might be unstable | Transport restrictions on boats, helicopters etc. | 5 | 1 | **6** | Take into consideration when planning logistics at design phase | |
| **Battery** | Chemicals | 314 | Harmful Chemicals are used in battery design | May be dangerous to dispose of | 5 | 1 | 6 | Make sure there are safe disposal methods that can be used | |
| | | 315 | | | | | | | |
| | | 316 | | | | | | | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Subsea HPU electric motor** | Rotating components | 401 | Electric motor rotor will rotate | Vibrations will propagate in the subsea system. vibrations induced effects on sensors, bolted connections, fatigue | 5 | 2 | **7** | Balancing of components before and after assembly | |
| **Subsea HPU electric motor** | Electric energy | 402 | changes in pressure level, pump condition, motor bearings etc. | Change in drawn current by the motor | 5 | 1 | **6** | Current monitoring may give a good indication of component condition and help in planning of preventive maintenance. Historical data should be saved for trend analysis. | |
| **Subsea HPU electric motor** | Electric energy | 403 | Startup current at o rpm is high | Overload of electric components | 5 | 1 | **6** | Take into consideration in design | |
| **Subsea HPU electric motor** | Thermal energy | 404 | When in use, the motor will produce thermal energy | Thermal energy build up degrades mechanical properties of component materials, built in lubrication etc. | 5 | 1 | **6** | Look at thermal build up in design, increase surface area or use forced convection | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Subsea HPU pump unit** | Cavitasion | 405 | Low pressure on suction side or at any location in the fluid path inside the pump | Cavitation, air bubbles and sponge effect on system as hydraulic fluid bulk module changes | 5 | 1 | **6** | Simulations and practical tests must be done under real operational conditions within operational limitations. | |
| **Hydraulic fluid** | Thermal energy | 406 | Subsea mounted HPU will discharge hydraulic fluid with a high pressure increase, this will increase the fluid temperature | Viscosity changes, loss of fluid properties/additives. Increased wear and tear on components, leaks to environment, increased maintenance cost | 5 | 2 | **7** | Heat exchanger must be introduced in circuit, sensors to monitor hydraulic temperature in different operations to control energy level in fluid. | |
| **Hydraulic fluid filter** | contamination | 407 | Particles clogs the filter | More work must be done to push the fluid across the filter→high pressure difference and chance for lower pressure on suction side of HPU. | 5 | 1 | **6** | Differential pressure should be monitored above the filter element. This will give an indication of component condition and help in planning of preventive maintenance. | |
| **Hydraulic fluid** | Volume control | 708 | Leak to environment somewhere in the system | Environmental contamination, loss of hydraulic fluid. | 3 | 2 | **5** | Hydraulic Volume should be monitored closely. Small leaks should be discovered. Level alarms should be implemented. | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Subsea HPU electric motor** | Electro magnethic phenomena | 409 | When powered, the motor will expose the nearby component with a small magnetic field | Might affect components/sensors to give faulty readings/signals | 5 | 1 | **6** | Must be addressed when detail engineering is undertaken | |
| **Subsea HPU pump unit** | Moving parts | 410 | Wear in components and bearings/bushings due to movements and rotation creates unbalanced, unaligned components | Rapid worsening of component , reduction in operational reliability | 5 | 1 | **6** | The change in vibrational pattern can be detected using accelerometers and trends can be analyzed. This will be the basis in preventive maintenance changes and planning. | |
| **Subsea hydraulic filter** | Component quality | 411 | Wrong filter grade/design is installed under preventive, corrective or planned maintenance | Filter will not performed as intended by designers | 3 | 1 | **4** | Include in procedures that filter grade/design is double checked. Choose filter design so that no other grade fits filter housing. | |
| **Hydraulic reservoir** | Contamination | 412 | Water in oil based hydraulic fluid | Loss of fluid properties | 3 | 1 | **4** | Drain plug in system for water settling and drainage. Under corrective maintenance | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Hydraulic fluid** | Contamination | 413 | Wear on components give rise to metal particles in hydraulic fluid | Increases wear in seal surfaces in pump, valves and in actuators. | 5 | 1 | **6** | Use magnetic sensors to build op historical trends on magnetic particle content. | |
| **Hydraulic fluid** | Contamination | 414 | Wear on components give rise to metal particles in hydraulic fluid. Metal is not magnetic | Increases wear in seal surfaces in pump, valves and in actuators. | 2 | 1 | **3** | Optical or other sensor design to be used. ROV retrieval of hydraulic fluid test can be used | |
| **Subsea HPU pump unit** | foreign objects | 415 | Bolts, fabric, gloves, nuts etc. are left behind after maintenance intervention | Damage to valves, pump unit, complete breakdown. | 3 | 2 | **5** | Introduce mechanical strainer (low pressure drop) on suction side of pump. Visual checklist inspection after maintenance intervention. | |
| **HPU setup** | Faulty component | 416 | Breakdown of complete subsea HPU | No pressure delivered to users | 3 | 2 | **5** | Consider redundant HPU setup with shuttle valve | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **HPU setup** | Hydraulic volumetric capacaty | 417 | Several hydraulic users are run at the same time | HPU cannot deliver required volumetric capacity, reduced pressures and prolonged sequence times. | 5 | 1 | **6** | Built in prioritizing of users and limits on how many commands are being executed at one time to guarantee fluid deliverance. Set up accumulators after HPU to have energy buffer. | |
| | | 418 | | | | | | | |
| | | 419 | | | | | | | |
| | | 420 | | | | | | | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Acoustic communication** | Shadow effects | 500 | Transducer on vessel or subsea is located in a shadow zone from the riser and/or other components | Signal disturbance | 5 | 1 | **6** | Use multiple subsea trancducers.Place transducers on arms that are expanded by ROV | |
| **Acoustic communication** | Signal refraction | 501 | In a vessel drift off situation on ultra-deep waters, the acoustic signal might be twisted as is crosses temperature layers in the water column | Signal disturbance | 5 | 1 | **6** | | |
| **Acoustic communication** | Signal delay | 502 | Time from signal is sent to it reaches the recipient is governed by the sound speed in water | Signal delay | 5 | 2 | **7** | Sequential control of the SIR | |
| **transducers** | Air bubbles | 503 | Air bubbles are present on the vessel transducer | Signal disturbance | 1 | 1 | **2** | Lowering of transducer to deeper waters, redesign so that bubbles cannot be trapped on transducer. | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Acoustic comunication** | Bandwidth | 504 | Little bandwidth is accessible on deeper waters, 1Kb/s at 4000 meters | Restrictions on information sent to vessel | 5 | 2 | **7** | Modification of communication protocol or system design. | |
| **Acoustic comunication** | Signal speed | 505 | Rapid escalating undesired event arise subsea, signal sent from SIR but takes time to reach operator on vessel | The operation can be beyond the point of no return before the operator on the vessel is made aware of it. Damages to SIR, FJ, DP and possible BOP. | 5 | 3 | **8** | Automatic operational limitations within the SIR control module | Not acceptable RIN # |
| **SCU-34 module** | Component fault | 506 | Electronic component fault in control module | Operational failure | 2 | 1 | **3** | Introduce inherent redundancy in electronic circuits | Already in design |
| **Signal cable** | Component fault | 507 | Cable from SCU to transducer is faulty | Loss of communication with transducer | 2 | 1 | **3** | Fallback on already redundant transducer | In place on existing system |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Signal cable** | Component fault | 508 | Failure in Cable from SCU to SIR SCM | Loss of communication | 1 | 2 | **3** | 2 communication cables to be laid out | |
| **Electric cable** | Component fault | 509 | Electric power cable to SCU-32 fault | Loss of electric power | 1 | 2 | **3** | 2 electric cables to be laid out | |
| **Cable seals** | Component fault | 510 | Leak over cable seals | Equipment failure due to water contamination of components | 1 | 2 | **3** | Use cable stabs imbedded in the water barrier. | |
| **Transducer** | Component fault | 511 | Subsea transducer failure | Loss of communication | 3 | 1 | **4** | Fallback on secondary redundant transducer | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| **Transducer** | Component fault | 512 | Vessel transducer failure | Loss of communication | 2 | 2 | **4** | Introduce secondary transducer on vessel for redundancy | |
| **Acoustic comunication** | noise | 513 | External activity introduces large amount of noise | Loss of communication with SIR | 1 | 2 | 3 | Take into consideration when planning head, procedures to be implemented | |
| | | 514 | | | | | | | |
| | | 515 | | | | | | | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
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| | | | | | Freq. | Consequence | RIN | | |
| **Umbilical** | Work over open sea | 601 | Extra clamps required to install cable while running riser joints | Additional work in heights over open sea | 5 | 1 | **6** | | |
| **Umbilical** | Component wear | 602 | Flexible umbilical comes in contact with components while kept dynamic by current or other similar forces. | Wear on umbilicals, failure of umbilical barrier, los of operational comunication/control. | 1 | 1 | **2** | Fixate umbilical with the right spacing between clamps. | |
| **Hydraulic conduit** | Hydraulic fluid | 603 | Time lag is introduced as the conduit must be pressurized | Precise control of SIR is difficult without design changes | 5 | 1 | **6** | Introduce large enough accumulator bank subsea | |
| **Accumulators** | Forces | 604 | Needed accumulator bank size introduces weight on subsea stack | Increase forces in subsea stack and wellhead. | 5 | 2 | **7** | Keep accumulator bank size to a minimum | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Freq. | Consequence | RIN | | |
| **Umbilical** | Forces | 605 | Weight of submerged umbilical | Must be compensated by riser tensioner. Depending on riser tensioner system capacity, this can reduce the liftoff capacaty | 5 | 1 | **6** | Increase riser tensioner capacity. | |
| **Accumulators** | Forces | 606 | Weight of accumulator bank | Must be compensated by riser tensioner. Depending on riser tensioner system capacity, this can reduce the liftoff capacaty | 5 | 1 | **6** | Increase riser tensioner capacity. | |
| **Hose reels** | Forces | 607 | Weight of hose reels | Reduced vessel stability | 5 | 1 | **6** | Must be compensated by a reduction in variable deck load | |
| **Umbilical connection** | leak | 608 | Leak in transition between umbilical and SIR control pod | Ingress of water in system, leak of hydraulic fluid to enviroment. Operational stop | 2 | 2 | **4** | Use similar technology as seen in BOP systems with stingers. Reduce the number of transitions. | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Freq. | Consequence | RIN | | |
| **Reacharge of energy subsea** | Weather | 701 | Wave heave over operational limitations in splash zone | ROV cannot be launched | 5 | 1 | **6** | Planning ahead and using good weather to charge accumulators or batteries | |
| **Stab operation** | Leak | 702 | Leak is present while recharging accumulators | Water ingress in hydraulic fluid, environmental spill. Deration of machinery performance | 2 | 1 | **3** | | |
| **Stab operation** | forces | 703 | Current, heave or other forces are present while undertaking ROV operations | makes it demanding to use the stab function to connect the ROV tools to the SIR intervention panel. | 3 | 1 | **4** | Land and latch ROV on dedicated intervention platform on SIR pup joint | |
| **Stab operation** | | 704 | Damaged stab seal while latching on to female receptacle on ROV platform | Leak in stab ref # 702 | 2 | 1 | **3** | | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Freq. | Consequence | RIN | | |
| **ROV landing platform** | Forces | 705 | Weight of additional landing platform | Must be compensated by riser tension system | 5 | 1 | **6** | Increase riser tensioner capacity. | |
| **ROV landing platform** | Forces | 706 | Increased current drag forces | Increase in horizontal forces in bop stack , taken up as a moment in the wellhead | 5 | 1 | **6** | minimize the drag forces of the platform | |
| | | 707 | | | | | | | |
| | | 708 | | | | | | | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Freq. | Consequence | RIN | | |
| **Electrical cables from control pod on LMRP to SIR subsea control module(SCM)** | Electric energy | 801 | Cable wear due to angular movement degrades isulation | Short-circuit of cable | 2 | 2 | **4** | Fuse in MUX control pod to ensure that the error does not propagate to BOP control system | |
| **SIR SCM** | Electric energy | 802 | Malfunction in electric/tonic components leads to short circuit | Loss of control of SIR, possible effect on BOP control system, well control issues | 1 | 5 | **6** | Fuse in SIR SCM/BOP control pod. All mitigating measures must be used to reduce the effects on BOP control system | |
| **Electric connectors** | Electric energy | 803 | Leak in connector seal | short circuit, loss of control of SIR, possible effect on BOP control system, well control issues | 1 | 5 | **6** | Fuse in BOP control pod. all mitigating measures must be used to reduce the effects on BOP control system | |
| **BOP control pos** | Electric energy | 804 | Additional components in control pods increases chance of error | May create operational deviations in BOP control pod, loss of one control pod | 3 | 2 | **5** | Keep additional components in BOP control pod to a minimum | |

| System activity/element | Hazard | Ref. # | cause/triggering event | Effect | Risk | | | corrective measures | comment |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Freq. | Consequence | RIN | | |
| **BOP control pos** | Electric energy | 805 | Additional components in control pods increases chance of error | May create operational deviations in BOP control pod, loss of both control pod | 1 | 5 | **6** | Keep additional components in BOP control pod to a minimum, only use the additional components on one of the control pods. | |
| **Communication** | Congestion | 806 | All the sensors, data logs and real-time info is transferred over the same info carrier as the BOP control signals | Bandwidth can be exceeded on the information carrier | 1 | 5 | 6 | Priority should be given to BOP control system information, safety critical info. Hierarchy system must be implemented | |
| **Topside components** | Component fault | 807 | The BOP control topside equipment will have additional components in connection with the introduction with the SHFW | Component fault propagates in the system with the effect of reduced operational possibility of the MUX control system | 1 | 4 | **5** | Design so that faults in the additional system does not affect any other parts of the BOP control system | Has been done historically with the use and control of cameras, additional sensors. Ref API 16 D, section 5.6.5 |
| | | 808 | | | | | | | |

Enclosed on CD:

PDF file of this master thesis

Excel file containing the rating of the different concepts, reference is made to Section 7.3.1